BEFORE THE

FEDERAL ENERGY REGULATORY COMMISSION

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IN THE MATTER OF: : Docket Number

PRICING PROPOSALS : RM01-12-000

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Commission Meeting Room

Federal Energy Regulatory Commission

888 First Street, NE

Washington, D.C.

Wednesday, November 6, 2002

The above-entitled matter came on for conference, pursuant to notice, at 9:35 a.m.

BEFORE:

MR. MARK HEGERLE

COMMISSION STAFF

APPEARANCES:

CYNTHIA S. BOGORAD, Attorney, Spiegel & McDiarmid, Transmission Access Policy Study Group

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LAURA J. MANZ, Director, Interregional Transmission, Public Service Electric and Gas Company

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APPEARANCES CONTINUED:

JACOB WILLIAMS, Vice President, Generation Development, Peabody Energy

RICHARD S. "RICH" BAYLESS, Director, Interconnected Systems, PacifiCorp

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MICHAEL DWORKIN, Chairman, Vermont Public Service Board

PAUL VASINGTON, Chairman, Massachusetts Department of Telecommunications and Energy

GARY W. GILLIS, Vice Chairman, Kentucky Public Service Commission

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APPEARANCES CONTINUED:

JOSEPH P. METTNER, Commissioner, Wisconsin Public Service Commission

SAM I. BRATTON, JR. General Counsel and Commissioner Emeritus, Arkansas Public Service Commission

P R O C E E D I N G S

(9:35 a.m.)

MR. HEGERLE: Good morning, everyone. My name is Mark Hegerle. I'm with the Office of Markets, Tariffs and Rates. In addition to the Commissioners who will be participating -- they're not here yet, but that's probably because they don't want to listen to me. They'd rather to listen to you.

I have with me a number of staff. I've got on my left here David Mead, Duke O'Neill, Kevin Kelly, Alice Fernandez from OMTR, Rob Gramlich from the Chairman's Office, and Roland Wentworth and Shelton Cannon also from OMTR this morning.

As you all know, the focus of the conference this morning is Pricing for Network Upgrades and Expansions. And one thing that we've found is that one term that's popped up in this discussion, "participant funding", has engendered a fair bit of debate and confusion perhaps. And one of the things we hope to do today is to resolve what that exactly means so we can actually talk on the same terms and get somewhere.

There's no doubt, of course, that the planning and siting processes for getting facilities built are going to grind to a halt if we can't figure out what the pricing ought to be for those projects and, you know, who benefits and who should pay for it. Certainly a state is not going to do that if they're not convinced the customers in their area are benefitting from the line. And perhaps more importantly, they want to just make sure that those that don't need the line won't have to pay for it.

The Commission stated in the SMD proposed rule and elsewhere that we need adequate transmission infrastructure to support competitive markets. An improved transmission grid not only ensures greater customer access to the most efficient generation, but in so doing it also lessens the need for reliance on market power mitigation measures.

To put this in a little bit of perspective, last December the Commission Staff presented a study before the Commission here demonstrating that large investments in transmission are more than paid back with even a slight decrease in the cost of generation.

The study, which I'm sure we'll make available on the Web site or elsewhere later today, showed that a 20 percent increase in a transmission investment, which at that time was about $12.6 billion, would need only to yield a decline in generation costs of less than 2 percent to pay for itself. To me, that seems like we'd get an awful lot of bang for the buck in investing in transmission.

So to the extent that cost recovery is in any way slowing down getting these facilities built, we need to come up with a solution today or real soon to get that out of the way.

With this in mind, I'd like to go over a couple of procedural items. First I want to say that a lot of folks have requested the opportunity to speak today, and obviously we weren't able to accommodate everybody. So what we have done is we've invited folks to submit proposals to the Commission for how they want pricing to be done. A lot of the panelists have done that, and a few others have as well so far. And I guess you could just e-mail them to me at mark.hegerle@ferc.gov and I'll make sure that they get around the Staff and the Commissioners.

Second, we play to work through the issues that are identified in the notice of this conference with each of the four panels today. We're going to try to go over the same things. Hopefully we'll build from one panel to the next. We can get a little bit of consensus on the first panel, a little bit more as we go through the day.

And as I said, some of the panelists have submitted proposals and hopefully we'll be able to have each of them give a couple of minutes on their proposals as we go through the day so we can sort of compare and contrast. Kind of like iron sharpening iron, so we really define and test and challenge the ideas and proposals that are out there.

We've set up a matrix over here that was included in the notice. Obviously, ideally we'd love to fill that in and have everybody say, yeah, I fully agree with what the pricing ought to be, and here's where it's going to go. I don't realistically expect that we'll get that far today, but if we can make a little bit of progress there, that will be wonderful.

Also, to the extent that issues come up I'm sure -- I know even in Staff discussions yesterday we got off on a rabbit trail on CRRs and things like that. I expect we'll start down that road today. What I'll try to do is sort of put that on a parking lot so that we can maybe raise that at another conference or at other more informal meetings later so that we can stay focused on the pricing issues that we need to get through today.

To get us started, I just wanted to briefly remind us of where the Commission has been to this point on expansion cost pricing. For the entirety of the open access area, the Commission has followed what we call the OR pricing policy for network upgrades, meaning if the customer needs a system expansion, he either pays the average system rate that is in existence for the embedded cost of studies or the incremental costs associated with the facilities they need for their service. They're prohibited from paying both.

In other words, the rate would be calculated based on the -- well, it's pretty much what I just said -- the expansion costs or the roll-in, whichever is higher.

Most of the time in the past this has resulted in a roll-in. That's the way the dollars have played out. But of course the purpose of this OR policy is to make sure that the existing customers are not harmed by additional investment to serve new customers. So facilities are only rolled in to the extent that they don't harm or benefit the existing customers.

And this is a protection that we want to maintain in whatever pricing scheme we come up with for the future as well. The only general exception that I know of to that policy is what we've done with generator interconnection. It's similar but not quite the same in the sense that the generator at this point has to pay up front for the cost of the interconnection facilities, and they receive in return credits against their transmission bill for the costs that they pay.

Also, with merchant transmission of course would be different in that they would pay for their facilities and then recover the costs through contracts and elsewise in their own way.

In addition, for ISOs we've had sort of a form of participant funding up here, you know, where there's needed upgrades for transmission service or interconnection, to the extent that they're included in the reliability plan for the region, those costs were rolled in. But I guess for the most part it's been that the regional plan covers reliability only, and a lot of those costs end up being participant funded, paid for incrementally, whatever words you want to use for that.

So you could argue we have some form of participant funding in place, if that's what you want to call it. We'll see how we define it today. If that's what we define it as, if the project clearly benefits one customer or a small group of customers.

That said, what we want to do today is define exactly what it means to participant fund a transmission expansion. You know, is this higher of an OR test and we've used the right thing, or is it something else that we need to use?

We want to identify different categories of investments and what types of cost recoveries are appropriate for each one.

Obviously there's some very difficult decisions to be made here. For example, when you think of generator interconnection, it's pretty easy to say that the generator benefits by the network upgrades to allow it to deliver its output, since it's the one that's asking for the money to be spent, and it's the entity most obviously receiving benefit.

But, you know, thinking of something different like a cross-regional expansion or an upgrade, you know, maybe the generator is the one asking for it and is benefitting, but perhaps there's customers on the other side receiving that power that benefit as well and we sort of need to work through who's the one that should pay for that? Should it only be the generator? Should it be the load? Both? What should it be? We need to decide what the right outcome is to get the facilities built. That's really what the Commission would like to see happen is getting the needed infrastructure in place.

You know, we've seen some areas where there's been transmission investment that's increased quite a bit. I know PJM just recently had a press release announcing $725 million in commitments for transmission investments. It's very encouraging to see that.

They use in PJM a regional planning process involving all the market participants, ensuring that the facilities needed to meet reliability standards and load growth get to be in place when they're needed. I understand their plan to say that the customer pays for these facilities unless they're already part of the plan.

I also know that companies such as ITC and ATC in the Midwest have done a lot to get transmission in place in a lot of facilities and we'll explore that a little bit -- a little later.

I think these examples highlight the fact that the approach to planning is an integral factor in deciding what the right way to go is with respect to pricing. They're tied hand-in-hand. You can't do one without the other.

And we need to decide, is an ITP driven planning with room for market solutions, or is a market-driven approach with the builder of last resort the better way? There's two approaches. You start with one and finish with the other or flip it. Is that the right way to get transmission infrastructure built?

Our goal today is to work through these issues and to come up with answers so we can, like I said earlier, fill in that matrix to the extent we can, or at least make some progress towards it so the Commission will have better information and a better record to make its decisions on.

Now the notice listed a number of questions. I've mentioned a few of them:

Defining pricing policies and categories of investments and matching the two.

Identifying barriers for the planning process to get the facilities built.

How much regional variation should be allowed.

Whether under market-based participant funding a market participant who funds the upgrade and receives the CRRs associated with them, should they also pay an access charge?

And a region that moves to market-based participant funding, how should customers transition from the transmission credits with the interconnection facilities right now to the CRRs?

Also, how can current wholesale network customers ensure that their load growth continues to be planned for?

And finally, what accommodation should be made for retail rate freezes? How do we recover the costs there?

I think we'll spend most of our time today covering the first of those issues, What is participant funding and which facilities should be paid for that way or other ways?

It will probably touch on these other ones as well. I just think that we have a lot to bite off in a short time here today.

Now, several panelists, as I said earlier, have offered proposals, and the Commission has reviewed one of them, the SeTrans proposal, earlier. So at this point I'd like to sort of get into talking about some of those proposals.

But just so that rather than me reading off each of your names so the folks listening at home can identify a voice and a name as they go along, if you all would just introduce yourself and who you're with across the row, and we'll get started here. And make sure your mikes are on too.

MS. BOGORARD: I'm Cindy Bogorad with Spiegel & McDiarmid for TAPS.

MS. MANZ: Laura Manz, Public Service Electric and Gas.

MR. MEHRA: Pete Mehra with Mehra Energy Consulting.

MR. WINSER: Nick Winser, National Grid.

MR. SCHNITZER: Michael Schnitzer with the NorthBridge Group on behalf of Entergy today.

MR. WALTER: Ron Walter with Calpine Corporation.

MR. LANDGREN: Dale Landgren, American Transmission Company.

MR. HEGERLE: Thank you all. What I hope to do, as we said in our instructions to you all, is we're not going to have opening statements so that we can just have a good dialogue started right away here.

So I'm going to start by asking Michael Schnitzer to present what SeTrans has and fill in some of the details on that so we can get started there.

But as we go along, one way of getting my attention would be just to stand your placard up rather than raising your hand in the air. And what I'll try to do is get reactions back and forth to this proposal and to the other proposals that I know are out there as well. And I'll obviously encourage Staff to jump in as well with questions.

Michael?

MR. SCHNITZER: Mark, thank you, and appreciate the opportunity to be here today. And I'll try and be as brief as I can so we can get into the conversation.

It might be helpful actually -- there was a handout passed around the table, and I think there are copies at the back. It's flow diagram boxes that I'll be referring to here, because I just think it will make it easier and go a little more quickly.

But the SeTrans participant funding proposal first of all I think began in the context of a market structure that looks a lot like the rest of standard market design, and it bears reminding what that is. It's financial rights, not physical rights for transmission. And I think as we look back at Commission policy, we have to remember that that was policy -- is the mike not on? I just need to speak into the mike.

MR. HEGERLE: There you go.

MR. SCHNITZER: All right. It's a financial rights, not a physical rights model, and the past policies of the Commission, other than in existing ISOs, have been sort of physical rights kind of models.

It includes some kind of resource adequacy requirement, some sort of reserve requirement or something like that as SMD contemplates. And there's the option for energy-only participation by generators. They don't have to be capacity resources and the like. So that's the rest of the market structure. It's got the LMP and all the rest that is in standard market design.

So then the question is, on top of that, how do you deal with transmission expansion and the like? And what SeTrans's proposal basically says is there's two generic kinds of transmission investments. There are those that are necessary for reliability, and there are those that are motivated by economics. And this chart that I referred to earlier tries to just talk about those two categories.

The reliability blocks are shown on the right-hand side. Those are mandatory. They have to be made when the RTO or the ITP determines that they're required as part of the planning process, and they are rolled in either at the zonal level or at the RTO level at the discretion of the RTO. The default in SeTrans I think most frequently it would be at the zonal or license plate kind of level.

There's a definition of reliability in the

SeTrans proposal. And that says, is the transmission investment necessary to meet the reliability criteria, be they NERC or those established in the RTO, is that investment required to meet those reliability criteria to serve load from the firm resources in the RTO?

And if the answer is yes, then that's a D or an E category of investment. If the answer is no, it's not needed for reliability, then it's an economic investment.

MR. HEGERLE: When you say "resources within the RTO", does that include merchant generation as well as the IOUs?

MR. SCHNITZER: It includes any generator that is either a network resource or a capacity resource that has met a deliverability requirement or an integration requirement, such as PJM would call it "deliverability". In SeTrans I think it's "firm resource". But it's any generator that counts from a resource adequacy perspective is included in that.

MR. HEGERLE: Is that deliverability within a zone or to a particular load? How is that defined?

MR. SCHNITZER: However it's defined by that particular RTO.

MR. HEGERLE: So at this point, SeTrans has not yet defined it or has?

MR. SCHNITZER: I believe there's a specific deliverability definition or firm definition in SeTrans. But whatever it is, those are the generators that count. So the non-energy-only generators, to use the SMD parlance, those that are integrated in some way.

So those are the generators that count. The load is forecast. You run the load flow models. You apply the security and reliability criteria. And if there are places where you need transmission investment because you just can't serve the load, then those are either category D or E.

Everything else, then, by definition, is for economics. It's because a generator wants to become a firm resource instead of an energy-only resource. Someone wants to try and get lower delivered prices. Someone wants to try and get higher prices at their node. Someone wants to get more out or through service.

And so what you see there on the left-hand side of the page, or at least one way that we categorize the particular economic investments, all of which would be participant-funded. There's the generator interconnection.

MR. O'NEILL: Mike, before you go on, let me clarify that you said forecasted load. So that let's assume that the system for existing load is reliable. So if it's reliability investments for forecasted load, it's load growth, it's the investments you need for load growth?

MR. SCHNITZER: Transmission investment required for load growth.

MR. O'NEILL: Right.

MR. SCHNITZER: Not generation adequacy investment.

MR. O'NEILL: Okay. But it's the transmission -- the reliability rubric is the transmission investment needed for load growth?

MR. SCHNITZER: That would be true for Category D. If, for instance, NERC changes their criteria and they decide --

MR. O'NEILL: All right. Okay.

MR. SCHNITZER: Then that would be Category E or something like that. But, yes. Without a change in criteria, one would expect that it was load growth in the main that would be triggering the need for those reliability investments. That's right.

MR. MEAD: Could I just ask another question? You said that, if I understood you, that it's transmission needed to meet load with firm resources. And as I recall, you defined "firm resources" as the resources that met the resource adequacy criteria.

So does that suggest that the transmission needed to make a generator resource adequate would not fit into the reliability category?

MR. SCHNITZER: That is correct. That

investment, the investment required to turn a resource from an energy-only resource into a deliverable resource or a firm resource or whatever you want to call it, you know, that's Category B on this little schema. That basically says. In PJM, that would be the deliverability test, you know, and I think the press release PJM funding to date is somewhere between $500 and $700 million worth of investment out of Category B -- Generators that have agreed to fund investments to the transmission grid to make them a capacity resource in PJM to meet the deliverability requirements.

MR. MEAD: Would there be any transmission left that would be in the reliability category? My understanding, and perhaps my understanding is incorrect, that in order to meet the standards of being a resource adequacy investment, the resource would need to have enough transmission to meet the load.

MR. SCHNITZER: They are not the same. The deliverability test that PJM has in place and that would be contemplated does not require every generator to be able to reach every load. And there still can be instances where you have a sufficient set of deliverable resources, but because of load growth in a particular area or something like that, the local transmission infrastructure is just insufficient right there to serve that load reliability, and you have to do something about it. Unless the generator locates there, you have to do something about it from a transmission.

MR. O'NEILL: Mike, you keep referring to PJM. I thought you were going through the SeTrans proposal.

MR. SCHNITZER: I am, and I'm just trying to relate the concepts in the SeTrans proposal to something else that people may be familiar with.

MR. O'NEILL: So that these are the concepts in the SeTrans?

MR. SCHNITZER: There is a deliverability firm resource requirement in the SeTrans proposal. It hasn't been as fully specified yet.

MR. O'NEILL: So it's vaguer than PJM?

MR. SCHNITZER: It's not as fully specified as PJM. That would be correct.

MR. KELLY: Mike, just one. You and I spoke about this once before, and what I took out of it as a summary is if the lights would go out if you didn't built it, it's reliability. Otherwise, it's not. Is that a fair summary?

MR. SCHNITZER: Yes it is. And I think if you'll permit me, there's a reason for that. The reason is, is that if we want a wholesale generation market that's competitive, then things that are economic in character I could have a generator and X amount of transmission here, or a generator and Y amount of transmission here, those things need to be able to compete with each other if we're going to get the lowest cost solution out of the marketplace.

And that's why anything that's not reliability we leave in the participant-funded pot, because that's part of the interplay between generation and transmission in finding the competitive solution that's lowest cost. Otherwise, we don't have any assurance we're getting there.

MR. KELLY: I wasn't trying to get to the rationale but just to clarify what reliability meant. Because when we started our conversation last time, I drew a wide box on what reliability meant, and as we talked, it got narrower and narrower to where reliability came down to if the lights would go out, it's reliability. If they otherwise stay on, if you didn't build it, it's not reliability.

MR. SCHNITZER: I think that's an acceptable shorthand. The longer version is from a defined set of firm resources and whether it's required to meet that load.

MR. HEGERLE: Michael, just so I can let you -- did you have more to go on your presentation?

MR. SCHNITZER: I think we sort of, because I don't want to abuse the privilege here, but I think we sort of covered Box B, which is, you know, sort of, if you want to become a firm resource or a capacity resource, a deliverable resource, that's participant funded, because that's how we get the siting incentive operationalized.

We've got LMPs which give price signals, but this is how we actually make it real for new generators that there's a transmission consequence to where you locate in terms of if you want to be anything other than an energy-only resource.

For congestion relief, for increased out and through, for those kind of investments, all of which may make sense, those are also economic. They're increasing somebody's price or reducing somebody else's delivered cost. Those are Bucket A.

And then in the middle is direct interconnection, those things that are required for safe interconnection before you generate a megawatt. Those of course are mandatory if you're going to be interconnected, but they would also be participant-funded in the SeTrans taxonomy. So I think that's the -- maybe I'll stop there.

MR. HEGERLE: So in simple terms you'd say that participant funding equals economic investment?

MR. SCHNITZER: That's right. And reliability investments are rolled in, and anything that's for an economic character is participant-funded and is voluntary in that respect.

MR. O'NEILL: Do the reliability investments get

CRRs? And who gets them?

MR. SCHNITZER: Yes. Any investment that creates CRRs. And so if reliability investment creates CRs, if, as in the SeTrans proposal, the default is that it goes to a zone, okay, then those CRRs are eligible for nomination by load in that zone.

So if you have a nominations -- SeTrans has proposed a nomination process on an annual basis for CRR allocation. So those CRRs that they're paying for go into the CRR inventory that they can choose to nominate. If the reliability upgrade gets spread over the whole RTO, then those CRRs would go into the general RTO CRR inventory for nomination purposes.

MR. O'NEILL: In this schema, could a zone be anything from a node to the entire RTO?

MR. SCHNITZER: The SeTrans proposal has specific zone or license plate proposals initially, and there are specific criteria I believe for what constitutes a zone that would not permit a node to be a zone in the SeTrans proposal.

MR. HEGERLE: Let me turn to your neighbor to your left and ask what this means for getting competitive generation in a system like SeTrans. Is this a good way to look at it or should we look at it a different way?

MR. WALTER: Let me start out by saying that as an independent power generator, what our interest in is putting very efficient generation in locations where we can reach our customers.

And our observation has been, I think as you pointed out in the beginning, that there has been inadequate investment in transmission and load growth has far outstripped our new investment in transmission.

And so that's one thing that I wanted to make very clear is that I think whatever we do, we ought to do it quickly and get on with it so we can support a transmission system that is reliable and we can get new generation.

Who benefits should pay the cost, but I don't disagree with the model of reliability versus economics but I think it ought to be a fair allocation of what the benefits really are.

I think our observation has been we pay now, as an independent power company, over $170 million in upgrades or interconnection costs and that's a lot of money. And in a lot of cases we haven't received the benefit in return. In many cases when we've been asked to pay, what we end of paying for is problems that have existed on the system for years and now that we we're wanting to interconnect with grid, all of a sudden we're being asked to fix problems that were there even before we decided to build a generator in that location.

In other cases, we have a very difficult time even getting any credit back for making the investment. That's not a uniform process. Obviously, I think some standard procedures would be helpful in this case.

And in other cases, we are actually being asked to provide upgrades that really help other players, rather than just ourselves, and so I'm not opposed to participant funding but what I think we need to do is to find a fair way to allocate it so that the benefit is derived to the people who actually pay the cost.

MR. HEGERLE: Is that in part the queuing problem where you might be first in line to get on, and pay a lot, and the next guy behind you doesn't have to pay nearly as much to get just as much benefit as you did?

MR. WALTER: Well, I think that's part of the problem, that's right. That's right.

MS. FERNANDEZ: I was wondering if it also is part of sort of if you put in a deliverability concept where, I mean I guess deliverability is not as fully defined in SeTrans, deliverability in PJM is deliverability to the Pool, that in that case it seems like the upgrades you would need to make would probably be narrower than if you do a deliverability concept where it's deliverability to a specific load? Is that?

MS. MANZ: That's a fair statement. The deliverability, and you can do this on a pool level or you can do it on sort of a sub-pool level if you will. But if you look at making all generation deliverable to all load, it's not a constrained period so you would indeed have, you know, you have the benefits of an aggregation or a collection there, that's correct.

MR. HEGERLE: So in a word, what would you call participant funding? How would you define that?

MR. WALTER: Well, for one thing, direct connection of a generating facility into the substation, whatever, is something that I consider to be part of the investment in a power plant. As you get beyond that, out into the system, that's where the concept of who benefits from the upgrade, is the upgrade necessary just because the generator came in or was it an ability to fix something that was already there, and you know who really benefits when a party comes in, so there ought to be a sharing concept I think beyond the direct interconnection.

MR. HEGERLE: Does an independent RTO or something like that or an ITP take care of a lot of those problems of this was here all along, why make this guy pay for it?

MR. WALTER: I'm glad you mentioned that because I think one of the biggest things that I see that really needs to get done is in a lot of places there's not an independent entity that makes these determinations about what the problems are, what's needed to fix it, where is it that it needs to be fixed. In many cases today, vertically integrated utilities are making these decisions and they are obviously making those decisions to their benefit which is to protect their transmission system and to protect their generation and not necessarily to provide the lowest, most reliable electricity product to the ratepayers.

COMMISSIONER BROWNELL: Could you be more specific about some of the experiences you've had in that regard? You've said that you've made investments only to find that you couldn't get access. You're being asked to make investments that really should have been done years ago, and that indeed there is lower cost power that could be made available to customers but is not because you can't get the power to them. If you could give us some very specific experiences, that would be helpful.

MR. WALTER: Thank you, Nora. I'm trying to think of a specific case without getting too specific. But there are areas in the country, and I think the Southeast is one of them, where there's a lot of generation that has been around for 30 or 40 years that has a heat rate which is how much gas it takes to generate electricity that's in excess of 10,000 or 11,000 btus per kilowatt hour. When Calpine first started getting into the business of building power plants, we looked at a lot of those areas where gas fired generation was on the margin because we felt that was a good, clean fuel to use for generation, and felt that we could build 7,000 heat rate plants in these regions where there are a lot of these older generation units and basically be 40 percent more fuel efficient. In other words generate at a marginal cost was 40 percent less than native generation that was there.

And taking advantage of 888, we said we'll have equal access to customers, we'll have equal access to the grid. Well we have found that in making a number of these investments -- and by the way we've invested over $10 billion in generation in this country -- we found in a lot of cases we can't get that more efficient power to the grid either because of difficulties in getting interconnection agreements, delays, exorbitant requests for credit, asking to fix problems that were on the grid, and I can give you some specific examples that we could write up and send to you all.

And in many cases -- and this is a little off the topic -- but I think without an independent party, not only are not good transmission decisions being made for who benefits, but also units are being dispatched out of economic order. In many cases, we have power plants that are 40 percent more efficient that are being operated down the street from power plants that are 15,000 heat rate units because it's not independently determined how units are dispatched, it's determined by the vertically integrated utility. So independence is an important part, whether you're talking about dispatch or whether you're talking about participant funding, or whether you're talking about decisions on how transmission upgrades get made.

We've got cases where we've actually paid for upgrades and then not been able to get to the market even after those were made, and we can give you some more specific examples on that.

MR. HEGERLE: Mike you have a response?

MR. SCHNITZER: Just a couple of points in response. First I think it's important to compare participant funding into the world that already has LMP as opposed to the current world where we don't. I mean this issue of dispatch and whether we got the right dispatch or not, once we have security constrained bid-based markets, we'll know. The prices will be public and we'll know if there's an LMP at a price at a generator that's running that's lower than the cost of that generator. That will send us a pretty interesting signal about that. We don't have the ability right now to integrate that market as easily as we can other than in PJM in New York and soon to be New England. So I think that LMP is a good solution, is part of the SeTrans proposal as well, but I think it's a solution to a number of things that Ron just talked about.

The second piece I would just say is that I didn't stress enough perhaps in the summary is that when some one participant funds something as opposed to the current world and the physical rights, you get all the property rights you create. And so right now you're in the situation of funding upgrades and if they are other than in the connection of requesting transmission service, you don't get anything for those because you haven't requested transmission service and indeed if you do request transmission service, and you pay for something that creates twice as much service as you are creating, as you're funding that you want, you only get the service you requested and somebody else gets the rest. So I think that the other element of participant funding is when you do fund something it creates a set of property rights which, yes, are independently determined what those property rights are. And the person who funds them gets them. And so you know what you've gotten effectively whereas in the current physical rights system, those characteristics are absent.

MR. O'NEILL: Mike, I understand the proposal when you talk about an individual upgrade for an individual customer but it seems in the real world there may be 70 upgrades going on simultaneously that are requested, and very often a central RTO might say look, you know, instead of doing these 70 projects as proposed, there's a way of putting in a backbone system and some radial lines that actually meet all the 70 needs with a lower total cost and a smaller environmental impact, so let's do that. And what happens then? Do you do a kind of cost allocation to the various parties of the lower total cost, treating the customers who pay rolled in rates as one party, in other words, they may be 90 percent of the system costs but they're like one entity that gets an allocation and the other ten percent may be divided among 69 parties that get their allocation?

MR. SCHNITZER: Well first I think the possibility that you suggest could of course arise. I guess you and I might have a different opinion about its likelihood. I mean, you know, PJM, there is a queuing and batching problem, and we have to deal with that requests that come in within a certain window are treated as contemporaneous and the like. And that seems to be workable and again, I think, you know, in PJM thus far there's been over half a billion dollars worth thus far worth of what we would call category B investments that have agreed to be funded without this issue arising.

But let's suppose that it happens. You have a bunch of people who've agreed to fund a set of projects and maybe some reliability investments, and then there's a better solution that's cheaper that gives everybody what they would have gotten from their individual investments but it's cheaper. I think the logical thing to happen there is for basically for a negotiation to take place under the auspices of the ITP to do the project that's cheaper and to see what the sharing of the cost and the benefits are. But that's different than the ITP saying I think this is an economic investment and you're going to pay for it. It starts with all the individual participants saying this is what we want and we're willing to pay this much and the conversation is about how much less they pay for something that they are willing to pay more for.

And so that's a very different kind of allocation than one that follows from the I-know-what's-best, this is the investment to take place, here's the cost allocation. That would not be a system that I think would make sense.

MR. HEGERLE: Did you have something to say, Laura.

MS. MANZ: Since we're talking about PJM an awful lot, I'd just like to sort of set the framework, sort of where PJM starts because it's trying to have anything that can be market-driven, and that assumes that the market-driven investments are through the LMPs, through the CRRs -- we call them FTRs, but for all intents and purposes they are the same -- and one of the key shifts that I've heard is that we're talking about the physical rights paradigm and that's where you really can't do a least-cost-security-constrained-economic-dispatch. So I think that's what happened is it's all the things that Mike said plus the fact that you transfer to a financial rights model. So you get your property rights and that's important.

But I want to respond also to the notion of who pays and how are you doing the planning. And the thought is that once you have the market signals, whatever you can have the market do, whatever you can have the market fund, is your primary driver. So if you can queue and you can get generators to say well, I can sell energy and that's my hookup, that's the first part. If I want do an additional sale of products, I want to sell capacity resources or ancillary service products or things like that, making those products deliverable to the market would be another level of investment in the grid, and that's where the deliverability study comes in. It's trying to be as less onerous or the minimum amount of imposition for those additional products to be delivered to the market, but it's the generators that are benefitting in that case by selling additional products.

It is only after all of that has been looked at that we look and say, well is there something given the NERC requirements, given the reliability requirements, is there something that hasn't been brought forward by the market community, and it's only that piece that isn't market driven that would be a regulated solution.

And even when we are in a regulated solution, where we can find beneficiaries, we ought to charge them, and it could be generators or loads or whoever the beneficiaries are. I don't want to say it's always loads because the beneficiaries could be generators or someone else.

And then there's beyond all of that, perhaps and not guaranteed but perhaps, another set of reliability upgrades, or regulated upgrades that you can identify the beneficiaries and that would be what would be rolled in. So that's sort of the complete package if you will, and I just wanted to get that out because we keep talking about, you know, fractions of PJM, and I hope that's helpful.

MR. O'NEILL: Laura, how many generators in PJM are energy only? Just roughly a percentage?

MS. MANZ: A small percentage. I don't have the number but it's a small percentage. Most generators find value in selling capacity as an additional product. Their choice. That's the important thing, it's their choice. There's no mandate to be a capacity resource.

MR. HEGERLE: As I would expect, there's placards up from everybody that has not yet gotten to speak. I have one last question for Michael and then I want to move on to the other proposals.

Is the reason why we need to wait on addressing Calpine's problems, for instance? Do we have to have LMP? Is there no other way to get there besides LMP? You know, because it seems to me that if there's competitive generation out there that wants to serve load, it's certainly at a reduced cost to load in the southeast for example, if they can do that today. Do we have to wait until LMP to do something about that?

MR. SCHNITZER: Let me give two answers. In terms of your question is do we have to wait for LMP to implement participant funding, you know, my answer to that question is yes.

MR. HEGERLE: Well I guess I'm looking at more is participant funding the only way to get cheaper generation in the southeast available to customers that want it?

MR. SCHNITZER: Well I think that every effort is made. Utilities have obligations to try and source their power for their retail customers at lowest possible costs and every effort is made to do that. I know that Entergy runs a procurement, for instance, I think on a weekly basis to try and integrate generation that it doesn't own or control with its own generation.

That's just difficult in a physical rights-based transmission system.

MR. HEGERLE: Are they willing to build for a muni or a coop or someone that wants to reach a lower cost generator or does that have to be paid for by the muni, for instance? Something that could be rolled in to access another resource?

MR. SCHNITZER: Well I think that, you know, when it comes to transmission expansion under the current tariff, Entergy, like any other utility, would be bound by the terms of the current tariff, you know, whatever they would be. And if that's the ore pricing and the higher of than that would be what would apply if that was the category that that investment fell into. You know, Entergy has been a proponent of LMP for quite some time and has been trying to get to the financial rights LMP system for some time, and you know is trying to get there as quickly as can, but in the interim, you work with the OATT as best you can under the circumstances.

MR. HEGERLE: We've heard from one transmission provider and one -- Kevin?

MR. KELLY: Could I follow up. I'm intrigued by your answer that you must wait for LMP to do participant funding. I realize there are at least three definitions of participant funding out there. My own happens to be beneficiary pays. And I think we've been doing some form of beneficiary pays historically as have states, why do you have to wait for LMP to do participant funding?

MR. SCHNITZER: Well perhaps my definition is different than the one that yours was. My definition of participant funding is basically saying it's voluntary. So it doesn't come out of a central planner saying this is in the collective best interest and I'm doing a cost allocation. It comes from, as Laura said, market-driven, the market-driven part of the situation where somebody in the marketplace says I want to fund this investment.

MR. KELLY: That is quite different. I

understand your answer now. We have had some confusion over different people meaning different things by participant funding and speaking past one another. Maybe at some point we can root that out.

MR. SCHNITZER: I think that would be a great improvement, and advancement of the debate.

MR. HEGERLE: Let me go to the customer side of it. Mr. Mehra, I think you've worked with Ford Motor Company for a while? How do you view this debate from the other side?

MR. MEHRA: Okay. I appreciate that, Mark. First of all, although I spend a lot of time at Ford, I'm here today representing myself as Mehra Energy Consulting, though I'll draw upon my experience while I was at Ford.

While I think although it's important to get transmission pricing right, we have to recognize that we're talking about less than five percent of the total pie, and the most important thing is how does it influence the other 95 percent? And are we creating a fair and robust and competitive marketplace for delivered electricity?

So I think almost any transmission pricing proposal has to be looked from that lens is what impact does it have on a robust marketplace. And I think to the extent even if it requires some imbalances or some unfairness in the transmission pricing segment to create a more competitive marketplace, I think we have bend in that direction.

Second comment I made based on discussions go on so far. Increased availability of generation benefits all customers. And I think to try to say that this customer benefitted or that customer benefitted from this resource coming on line is a farce quite honestly; all customers benefit when there's more generation available, and all customers should pay for it.

Thirdly, all general transmission costs are eventually going to be paid by the customer, so let's get out of this bit, you know, that of trying to allocate it to A, B, C, D, portions. Let's get to the customer right away, the major industrial customers, the load-serving entities, zones, pricing zones, what you call them. Let us put most of the cost to those people, they're going to pay for it and allocate it to them beyond direct interconnection costs that a generator should pay for I think, quite honestly. We're dancing on the head of a pin when we try to look at, you know, who to allocate costs.

Also recognizing the fact that you made Dick, or Kevin, you made, rather than building transmission in piecemeal, in most effective is done in chunks. In trying to allocate, you know, you were the first one to come, or you the second one to come, what are the financial rights or the physical rights or that, quite honestly is a farce because if we build the transmission system correctly, all the financial rights should go away. There should be zero value if we have a good functioning transmission system, that's what we really ought to get to. You know, the ideal would be there are no bottlenecks.

The last one comment I make is let's not start from the assumption that you've got a very fair allocated system that exists today, and that's a problem that we, as a customer, have had consistently. One of the cases that I mention rather specifically when you were in Pennsylvania, we had an electronics plant out there, Ford Motor Company has, and we were having over a dozen outages a year.

And the utility's position was it was met the state's regulated criteria and if you wanted a transmission upgrade, you paid for it. My position was, that's an unacceptable level of quality. You wouldn't accept a dozen outages in a vehicle, would you? Because I talked to the CEO that day. And I said, you've got to pay for it. And his argument was no, this is an incremental impact. I think that's quite honestly a farce.

You know, when you get back into defining local reliability what is the definition of local reliability? You know, if you're going to have manufacturing that's competitive in this country, quite honestly, you cannot have more than one what I'd say a momentary or a deep sag in a period of about two years. That's the sort of level of quality we need to be competitive. Most of these plants, a utility may say it's oh, it was less than a second, it was ten cycles, but the manufacturing facility is out for four hours, eight hours, as the impact of that one cycle. And so we have to take a broader definition of what is reliability.

MR. HEGERLE: I know that TAPS looks at things a little bit differently with respect to the economic versus reliability roll ins than perhaps SeTrans has maybe siding a little closer with what Pete just said.

MS. BOGORAD: No. I think we're basically at the other end of the spectrum. We think there can be some room for some incrementally charged upgrades but if the Commission keeps its eye on the bottomline, which is how do you create the robust competitive markets for SMD, it seems to us the only way you're get there is through some form or roll in. You know, and I say that as transmission dependent utilities who are trying to meet their load reliably at low cost. We are not in the business of trying to ship power from here to there just to have fun doing it. When that carpetbagger's coming in, we are the load. We're the guys paying the embedded costs. So we're not trying to avoid costs but we think that if the Commission's objectives of

SMD have any chance of success, the only way that's going to happen is if you get the investment in.

One of the things that strikes us as the infrastructure today is a) not there and b) to the extent it's there it's very uneven. But the unevenness doesn't have anything to do with what customers did. Those are choices made internally by vertically integrated utilities. You know, some for very good purposes to minimize overall costs looking at your generation transmission choices in another era, and that's great.

In our view, because we're not starting on an even tabula rosa, we have to get the four-lane highways in; we have to get -- customers deserve more than what Mike Schnitzer said, which is just to have the lights on.

We've all been paying our rolling costs for years, for access to the grid. And if I happen to have moved into the wrong neighborhood, without knowing I was in an ill-served neighborhood, I didn't check my transmission access when I bought my house in 1985.

You know, that could become very important, if, god forbid, states actually have the LMP signal come through. I don't know whether I'm in a good area or not.

There's something wrong with this picture, and I cannot figure out how load can get together. I mean, this has been very generator-focused, but how load, especially in a retail access area, it's not clear to me, who would get together to fund the economic upgrades, so that load could get access to the grid and access to the competitive markets.

And if you don't do that, all you're going to have is more constraints, more market power, more market power mitigation, higher costs, and not what any of us wants.

I guess the tax proposal is basically, don't rely on market participant funding where it's not like to work.

And we have a broad view, a much broader view than others on where we don't think it is going to work.

And certainly we don't think the upgrades to allow load reasonable access to the markets, so I don't get ding'd because I happen to have picked the wrong neighborhood to move into, not knowing it, and not having any control over.

And it could be me; it could be a load-serving entity, or you can take it at any level. But, you know, these decisions were not made with the current market participant proposal in mind.

So, you know, certainly upgrades -- provide on customers, reasonable access to the competitive market, to accommodate load growth, and it's not only the way SeTrans is doing it; it's just the load growth that you can meet with existing resources.

Well, that doesn't take you all that far. You know, we're talking about load growth in terms of the adequacy to meet load growth and meet the Commission's adequacy expectations, as well as those in states.

And to achieve and maintain the simultaneous feasibility of existing firm reservations and CRRs, once they're out, we are very concerned, as many of you have heard from us, that once that when you go to a simultaneous feasibility test, there's not going to be enough CRRs to support exiting firm reservations.

And our view is going to be super-high priority for the Commission to get the transmission in to maintain those expectations on which people finance millions, billions of dollars of investment.

We would -- and leave some room for participant funding in connection with upgrades where it's not consistent with the region's long-term plans to meet these other requirements, and there could be a but-for test, taking account of other benefits, so people just don't get socked.

The other thing we have in our proposal, and then I'll -- I guess there are two other things I want to mention -- one is that we think that to work for load-serving entities, the CRRs need to be assigned in a way that matches the resource.

If I need equivalent of a 10-megawatt upgrade for 200-megawatt resource, a long-term CRR for 10 megawatts that I get by participant funding, is not going to allow me to go out and finance that 200-megawatt unit.

I need a CRR to match my units, so -- to load. So the way the market participant funding proposal works, we don't think actually will support the generation adequacy this Commission needs and we all need to make SMD in the market work.

So, our proposal would have the CRRs match the resource if it is a designated network resource, and, you know, if it's somebody who doesn't want to sell it to a network customer in that RTO or in some other RTO, that then you can do it the way Entergy is proposing.

And, finally, one last component is that we recognize that there is an export problem in certain areas, but we think the way to deal with the export problem is not through participant funding, but through a TransLINK styled rate design or some variant on that where you have a highway charge, which captures the larger regional -- and then zonal charges where both load and generation pays.

So, if you have a heavily generator zone, the generators will be picking up a portion of the revenue requirement, and that will help alleviate that problem without dragging everything else down.

MR. O'NEILL: Cindy, do you have any members in Maine, Kentucky, or Arizona?

MS. BOGORAD: We don't have any in Maine; Kentucky, we do have members.

MR. O'NEILL: How do they feel about your proposal?

MS. BOGORAD: They are TAPS members, and they have not told me that they disagree, and have been at the TAPS meetings where we talk about it, so I think they are onboard. I think the --

MR. O'NEILL: They disagree with the Governor of Kentucky's position.

MS. BOGORAD: They may or may not disagree with the Governor, but I think the -- I think the key is, we're not saying sock Kentucky. We're saying that there are better ways to deal with the Kentucky situation than crippling the ability to have a competitive market any other place in the country.

And I would -- you know, I think that if Kentucky has a problem, fine, let's roll up our sleeves and solve Kentucky's problem. And if there is something in the rate design that has to better allocate costs to all generators in Kentucky, that's fine, but let's not go to a totally different model that makes it impossible to have the competitive market.

MR. O'NEILL: How about Louisiana?

MS. BOGORAD: Yes, we have TAPS members in Louisiana.

MR. O'NEILL: Do they favor the TAPS proposal?

MS. BOGORAD: As far as I know, so, yes, no; I think it is -- we are not trying to -- we are the guys who pay the embedded costs. I mean, we are the people who will pay these costs.

But we also think that the benefit which we're trying to get to is a competitive market in generation, and we think the only way you can get there is to roll in the transmission costs in some way to get the stuff in.

MR. O'NEILL: Some people --

MS. BOGORAD: And we all have access to the market.

MR. O'NEILL: People in those states argue that if you built a lot of transmission to get out of those states, that the rates to your customers, the entities that you represent, would go up.

MS. BOGORAD: Well, that's not the perception of the TAPS members who are hoping, actually, to benefit from competition. That's why we're all here.

And that's why we have supported open access and RTOs, and all that jazz is to basically to make it work, and we don't think it's going to work with participant funding.

MR. KELLY: Cindy, what I heard you say is that you'd have market-based participant funding play a very limited role, which I took to mean that somebody has to actually volunteer to pay; they have to take out their checkbook, write a check to pay for new transmission, and that's participant funding.

MS. BOGORAD: Well, I think we'd actually give it a somewhat broader role than that, but I will accept that our role is a pretty restricted role.

MR. KELLY: But I really wanted to get to the alternative of rolled-in, by giving you two scenarios and see how you'd characterize it. One is, let's say you're in the Midwest ISO, and just a quick example, maybe not a good one: Suppose that the northern tier states -- Minnesota and states near it -- decide that they need to upgrade their transmission systems to be more resistant to ice storms.

And that the utility service areas up there would pay for that -- would pay for it; it gets rolled into the rates of their customers, so I'm using the term, "rolled in," but it's not necessarily rolled into the rates of the entire Midwest ISO.

What I'm teasing out of you is whether rolled in means rolled in locally or to the whole RTO. Let me give you the second example, so you can answer the two together.

Maybe you've got a lot of generation in Mississippi that wants to sell into the Midwest, setting aside uncertainty of where they would sell in the long term, just to make the example simple. Let's say we know they want to sell in the Midwest for 30 years, and that gets rolled into Midwest rates.

I think, you know, from the Mississippi point of view, that might be participant funding; from the point of view of the people in the Midwest, it is rolled in.

Would you call -- when you were calling for roll-in, were you calling for rolling into, let's say, a SeTrans rate? Rolling into a MISO rate? Or?

MS. BOGORAD: Well, that's a good question. And I think part of the concept of a translink type of proposal is that you would make distinctions between what facilities favor everybody in the region, which should be in this highway rate, which would be broadly shared, and these more zonal rates, where the costs would get assigned to both generators and loads, and I don't think, especially as the Midwest ISO grows and grows, has some notable pockets, but grows and grows, then I think, you know, you should --

It makes sense to look on subregional areas on who benefits, so, you know, I don't think we were saying that every line put in anywhere in the Midwest ISO has to be absorbed by everyone in the MAPP SPP, main areas, so there --

I think there is the potential for -- and actually I think it makes sense to treat these things and look at them as cost allocation decisions, and we're not adverse to cost allocation decisions, looking at who benefits.

But to sort of flip that around and say the loads in those areas have to somehow either come forward and say, okay, we want to fund that, is not what we think is an acceptable way.

MR. O'NEILL: So you're okay with beneficiary pays.

MS. BOGORAD: But it's a very broad beneficiary pay. And I guess that goes --

MR. O'NEILL: Broad. I mean, is that -- you know, we've gone back and forth. How broad?

MS. BOGORAD: I guess, you know, someone else was saying we think many people benefit from the competitive market. We don't think --

MR. O'NEILL: If we show that people don't benefit.

MS. BOGORAD: Well, then maybe we're not doing the right thing overall, but presumably we're here because --

MR. O'NEILL: Well, no, but do you think that people in the southern part of MISO benefit from the Minnesota upgrades for ice storm problems?

MS. BOGORAD: You know, maybe not, and maybe that's where -- that might be something where in a broad area, you assign it. And, you know, there is some room to think about what should be done on a license-plate basis, and what should be done on a super-regional basis, especially as these regions get very large.

MR. HEGERLE: So we can allow some other very patient speakers to get a chance, can I summarize and say, in part, that in the planning process, as opposed to where perhaps SeTrans was, you would say there needs to be an element of economic upgrades for competitive reasons, included in that process somehow, and how they are allocated, as Dick was exploring, you know, we need to work on a little bit, but there just can't -- can't isolate the economic and reliability completely. Is that fair?

MS. BOGORAD: Yes.

MR. HEGERLE: Okay, Mr. Winser, you have been very patient. We'd like to hear what National Grid has to say.

MR. WINSER: Actually, I agree with a lot of what's been said, particularly by Cynthia, Pete, and Ron. And I think the critical distinction which has come out of this morning's debates is the one about whether we're talking about whether the beneficiaries pay or not, or alternatively, whether this is voluntary or mandatory to pay.

That, it seems to me, is where this debate has not go through to clarity in the past. And I am very comfortable with getting as close in possible in transmission pricing to beneficiaries, ultimately beneficiaries paying for upgrades. That seems to be exactly the right thing to do.

There will be questions of how close you can get to it without an awful lot of rules and an awful lot of debate about who the beneficiaries are, and some rough justice may be required there.

But I am in favor of beneficiary pays. Where I -- Mike and I agree on one thing today; we agree on the taste in ties this morning, as you see.

(Laughter.)

MR. WINSER: But --

MR. HEGERLE: I promised not to bring that up.

MR. WINSER: Embarrassing that we sat next to each other.

But apart from that, where Mike and I really differ is -- very nice tie, if I may say so, Mr. Chairman.

(Laughter.)

MR. WINSER: Expensive, aren't they?

(Laughter.)

MR. WINSER: You know, I've lost my train of thought.

So, the big issue is voluntary. Transmission investment in the U.S. is, by my estimate, running at something like a tenth of what it should be to really facilitate a good market in generation, which is very much picking up Pete's point, is absolutely critical, because it's such a large component to the cost.

Even in PJM, it's running at something like a quarter, and, anecdotally, PJM market participants say that while deliverability is bringing forward some market participant-funded type investment, so far, the easy stuff has been picked up -- the stuff that is quite close to home, not the assets which are really shared, really serve more market players than one -- normally one or two.

And so, you know, my heart goes out to Cynthia when she says, you know, taking that argument further, to the extent that we are in a voluntary system, that sounds to me like if we want to build transmission, we have to pass the hat around.

How, exactly, do you pass the hat around in a retail access environment? And I actually had a very good look at the transmission system where I was moving into, because it actually ran alongside --

(Laughter.)

MR. WINSER: But I can understand that people may not.

So, the passing the hat around aspect of this is a very worrying one, and makes me lean much more to system which very clearly allocate the costs to beneficiaries, but do so once due process has been gone through and transmission investment has been made on a mandatory basis.

Because, as you get into the system, so many of these assets really benefit -- and it's very difficult to find assets, actually, which don't benefit, you know, quite a variety of players.

And so to have a voluntary or a pass the hat around sort of system, is bound to lead to -- I hardly dare say it -- even lower levels of transmission investment.

And really to make success in these markets, we need transmission investment to increase, and therefore we should be leaning towards the mandatory side of this, un-politically correct as that may sound.

I would, however, sort of nod towards some of the particular issues in Louisiana and Maine that have been quoted, and we've circulated a proposal that does cover those issues, I think.

What we believe is that there should be a beneficiary pays, but generally on a mandatory basis, sort of system. We would move to the voluntary pass the hat around system where it is investments outside of RTOs, between RTOs, and we would also obviously look at that for local generation interconnection, and even looking at the parts of the switching station that are required for that interconnection.

Furthermore, I would say that it would be sensible, having looked at the sort of problems of Maine and Louisiana to have, if you like, a bolt on to that system which says that where a transmission investment is predominantly needed to ship power from an area of cheap generation, which we would, as customers, want to tap into, to a relatively distant market and possibly going across areas which aren't going to benefit, that that may well be a place to reach for the voluntary market participant funding type of approach.

And I would throw out to the Commission, the idea that we could construct some sort of test which said that if in a particular area, generation is dominant, let's say five or ten times as much generation in a particular area, you can pick a number, as demand, and people are looking for upgrades from that region to a much larger market to supply, that that may well be put on a market participant funding basis.

So, say -- and we have --

MR. O'NEILL: Do you have any examples of where it would be five or ten to one?

MR. WINSER: I don't, Dick. I mean, we throw it out as a way to get through this sort of -- this issue.

We could look at the statistics and maybe the answer it two; maybe the answer is three. I mean, I'm not saying it should be a very high number.

What I'm saying is, let's reach for the rolled in beneficiary pays type of system, where we don't reach for that, might well be where it is very evident that there's a new area, maybe an existing area of cheap generation which is trying to get to a market.

And I can fully understand the arguments of those that say, well, those investments aren't benefitting a particular state where the generation is, or one in between, and that that should be a place for market participant funding.

And I believe that that should be the way through this debate, and I would commend that as a suggestion to the Commission.

MR. HEGERLE: Mr. Landgren?

MR. LANDGREN: Thank you. American Transmission Company is a stand-alone transmission company, and we have been, as you mentioned, focused on getting things built. We think one important focus right now to getting things built is to view transmission as an enabler to the system.

And I think you heard this from some of the folks, not as a competitor, in the marketplace; that may ultimately be a long-term policy goal, but if you want to get things built today, we think transmission needs to be viewed as an enabler.

I do agree with the points that Kevin and others have made, that there are multiple uses for -- multiple needs for which you need to get new transmission built.

You don't just look at system reliability, you just don't look at access to the market. We have load growth where we have our distribution utilities asking for transmission and distribution interconnections.

We have generators who have interconnection requests, so you have generation of transmission. Some of those are designated as network resources to meet local load growth. Some are clearly in the market to be merchants.

We have preexisting congestion or limits. We have infrastructure updates. We have many parts of our system that are 70 and 80 years old that are literally falling down.

So we have all of these various needs that are out there, both today and projected into the future.

Transmission investment is lumpy. The whole notion that you can identify a single beneficiary and a single need for a specific facility, we think is relatively unlikely, particularly if you look over time.

And we do believe that if you try to follow the kind of approach that has been proposed by others, you're going to get a suboptimal system, because you are, indeed, designing parts of the system to meet single needs, rather than taking into account, the multiple needs that we know are out there.

We do identify preexisting conditions, and I think Ron identified the fact that on many systems that he's being asked to pay -- to solve preexisting conditions, we are very up front. We actually publish where there are weaknesses on our system, and the generator can see that up front, that we are not going to try to charge them for those conditions. But they do exist in our system, and I'm sure they exist on many systems.

Another benefit of viewing transmission as an enabler is that you cannot predict the future. I have been in utility planning for upwards of 30 years, and, you know, looking back every five years to what we thought the future was going to look like is a very humbling experience.

So to start looking at transmission needs, based on a particular load forecast or a particular assumption about what generation is going to be in place, and then determine whether or not the transmission is needed for reliability or for economic purposes, I would challenge the ability to do that in any kind of an accurate way over a long period of time.

The value of a strong transmission grid is to be able to give you the ability to have diversity and to account for many alternative futures.

MR. O'NEILL: Dale, can I ask you a question? PJM thinks they can do what you're saying you can't do.

So do you have any particular bone or gripe with the PJM system?

MR. LANDGREN: I am not particularly familiar with how PJM is doing it, and I really don't want to pick a bone with them. I'm just telling you our experience and our view of the world.

MR. O'NEILL: But you have one position that says it can't be done. PJM, and, I believe, SeTrans believes it can be done, and it would be nice to figure out why.

MR. LANDGREN: I'm telling you why I don't think it can be done. If they, indeed, feel it can be, then I think we need to go through the points and say why isn't the issue I brought up a particular problem?

MR. O'NEILL: Okay.

MR. LANDGREN: But I do think that if you look at the ability to handle diversity, you know, really, the need for my company grew out of 1997 and 1998 when nuclear plants were shut down and we didn't have appropriate amounts of transmission to meet the needs in the state.

But if you have a robust transmission system, you can accommodate unexpected load growth; you can accommodate unexpected generation shutdown, or new generation locating elsewhere. That's the value of having a strong infrastructure in place; it gives customers more choices, which is what Cynthia wants her members to have.

So we do believe there's kind of a social good, a public good, to having a strong transmission infrastructure in place, and to us, that argues for, along with the issue of multiple needs being met in an efficient way, that argues for a Commission policy which tends to view as a default, the rolled-in mechanism.

And we do believe that there -- and we have in our proposal, that there are some facilities that are built which have value beyond the local footprint. In our case, we are building a few lines which we do believe have benefit outside our system.

We know that there are lines that need to get built in Illinois or Nebraska that will have a benefit for our customers. And there needs to be a way to share those costs.

You know, whether you call that participant funding or not, we do believe that to the extent that you can clearly identify someone who benefits, you should try to have a pricing mechanism that does that. We just think that over time, it's very difficult to do that for most elements in the system.

You can clearly identify a plant that has regional value. Our proposal is that the originating transmission owner can propose what they think is an appropriate split. It's 70 local benefit, 30 percent regional.

The independent RTO can do some power flow analyses, and probably only over a relatively short period of time, like, five years, and either validate that or change it.

And then the part that is regional gets put into a regional access charge, so the customer is going to be paying their license-plate rate for their local facilities, added to that will be a regional component, and it can be subdivided.

Cynthia, in response, Dick, to some questions from you, said you could subdivide the region, because we agree that a facility being built in northern Wisconsin and northern Minnesota, that the people in MISO who live in Oklahoma are probably going to look at that and say, what does that do for us? And we would agree with that.

So there may need to be some subzones within the RTO footprint, if the RTO is big enough, which MISO is. But clearly we believe in a fairly simplistic way.

And what I put in our proposal is, you don't need to be exactly right, you just need to get it close; you don't need to be down to the decimal point.

But to get it within five decimal points and to say that cost is a regional cost, because the region benefits from it, and then that gets assigned to the region in question --

MR. O'NEILL: Who makes the determinations of what transmission gets built?

MR. LANDGREN: In our view of the world, if you have an independent transmission company, they would be developing plans for their own footprint. The RTO within which they resided would be looking beyond the footprint of any one transmission company and asking are there better solutions for the region?

The RTO would also be doing more detailed planning for the vertically integrated utility, because, again, they're not independent. And between those combinations, you would come up with a plan.

But, again, from an independent transmission perspective, I think it's the view that the Commission took in TransLINK, that they should be allowed to develop their own plan and move on it for facilities that truly have mainly local benefit within their own footprint.

But you would get that ability, and as Kevin pointed out, there might be a different way to do it regionally that the RTO --

MR. O'NEILL: Who makes that determination?

MR. LANDGREN: Ultimately, the RTO would make the determination. If the independent transmission company had in their plan, facilities that they felt were local, and someone wanted to challenge that, it would go to the RTO and the RTO could look at it and say we either agree that it is local, or we believe that it's partially regional or totally regional, but they would have the determining --

MR. O'NEILL: Would anybody get to say it's not needed?

MR. LANDGREN: Clearly, that would also be an option. Again, we all go through siting procedures in our states, as well, that if a facility is not needed, you would have the ability to do that.

MR. O'NEILL: That would be a state determination?

MR. LANDGREN: That would be a state determination. Again, the way MISO was set up, MISO can't preclude a transmission owner from going ahead and trying to get the ability to get a facility built.

What they can do is say it's not in their plan or we don't think it's needed. And if you can go to your local authorities and justify it, even though your regional independent organization says it's not, all the more power to you.

MS. FERNANDEZ: I was wondering if I could get -- it seems like one of the points we seem to have in controversy is that there is a general agreement reliability upgrade that gets made. But there seems to be other upgrades that are perceived to be -- or some perceived to be necessary for a competitive market.

And it seems like we have heard from a number of people who think that they won't get made under a system where there is participant funding.

I was wondering if I could get Laura and Michael to respond to that, and maybe then we could get Nick and Dale to sort of see if we can get into a debate on that particular point.

MS. MANZ: I'm from Jersey, so I can kick things around pretty well some days.

(Laughter.)

MS. MANZ: So let me try. I think what I'm hearing here -- and especially on the issue of participant funding -- and let me go all the way to what would be called default in some of the conversations here.

I would call it last resort, and so that's sort of where I am. And what occurs to me as we're having this conversation is that how such a small part of the cost -- because that's what we've heard -- we're talking about a small part of the cost.

Well, the small part of the cost has the potential to completely undermine the market, if we do this wrong. So we're talking about a very important topic, even though it might be a small percent of the cost.

And as I'm thinking through some of the things that I've heard here, what we're talking about when we spread the funding across everyone, is what we're really doing is saying it doesn't matter where you locate, and it doesn't matter, you know, sort of how we run the system. Like those pricing signals that we tried for years to get going, are now going to have the legs cut out from under them, because we're going to spread any pricing differences in this other component of the cost.

So, I'm very concerned about that, and there's another part here, which is, we are coming back -- and I really appreciate Pete's description of, well, we've made a mess of things for so long, so what? You know, let's keep going.

Well, I think we have a real opportunity to stop the mess, and to be much more precise about what we're doing.

And so the other part of this is, we want to stop the cross-subsidization. And so when we talk about spreading things all over, we again introduce cross-subsidization and I'm not sure that's what we're looking for.

Everything I think we're moving toward in developing markets and developing these working markets, is to get rid of the cross-subsidization, get rid of the sort of non-locational aspects of this, and get rid of, you know, sort of the ability to sort of hang on to everybody else; that we really are trying to get each entity to stand sort of on their own and do that through the markets.

MS. FERNANDEZ: Is your point basically then that you wouldn't have a perception that there are high-voltage lines that would be better for competition, a competitive market in an area if there was an upgrade on it? Do you see that that --

How is that going to get done, or is it something that you figure through the siting of generation, you're going to reduce the need for the upgrades on the high-transmission lines?

MS. MANZ: It's a good question. Rather than try sort of the voluntary/mandatory split, I think of it as a market-driven set of things; that regardless of the voltage level, if people think that they are going to benefit, it's cost-beneficial to them, I almost see that as they bring the full hat, if you will. They bring the full hat, and say, we have market benefits from this, and here's our money. We want not only the upgrade done, but we want the property rights.

And I think Cynthia touched on a very, very important point; that when we do the upgrades, we expect that the CRRs come along with it, so we get our money for having made this investment.

So I'm not so inclined to say, well, all voltage levels do this, as much as I'm inclined to say we now have market signals. And there are those who are going to come forward and say I benefit from changing these prices; I'm willing to come with my hat full of money, unlike the other thing, which is the pass the hat around.

I look at those as the mandatory or the regulated upgrades that said hat's empty, and we now have a regulated solution that says you've got to help us fill the hat.

And so that's what we're talking about, I think, under the regulated paradigm, is, is the hat filled by those who benefit? And it may be the market signals or it may be a reliability issue. We talked about the issue; we talked about this local reliability issue.

Who's benefitting from that? They should put the money in the hat. And it's only when we can't figure out who's benefitting, that we pass the hat to everyone.

MR. O'NEILL: Laura, do you or PJM break down the transmission investments by interconnection, deliverability, and reliability? In other words, how much is going to each one?

MS. MANZ: Yeah, we break them down in the sense that there are transmission upgrades that the market brings forward.

MR. O'NEILL: What I meant to say is, do you have dollar figures of how much? We've cited how much investment is being made. You break --

MS. MANZ: Just rough figures for -- I think the number I heard today was 725 million. That's a good enough ball park.

The market participant-funded portion of that is about a half to two-thirds of that amount, and then the other remaining third is what we would call reliability upgrades. Those are the ones that weren't driven by the market signals.

MR. HEGERLE: We are running low on time. I think we want to get Michael's response to Alice's question, and then I'd like to be able to go to that chart over there and at least try to nail down a couple of things, if we can.

MR. SCHNITZER: Okay, I'll try and be brief here. I think if transmission costs didn't matter, if they were not significant, we wouldn't need this day and we wouldn't have needed a lot of other days that we have had.

But the plain fact of it is, in most of the empirical experience that I'm aware of, is that a generator location decision can have a big impact on transmission on the margin of $100 or $200 a kilowatt or more.

And so it's not a matter of it doesn't really matter, and so we should socialize everything or we should roll everything in; it turns out that it does matter. So if you want a competitive generation market, and you want people to make the right tradeoffs between locating in remote areas or locating close to the load or locating in good electrical areas or locating in bad electrical areas, and if that has a serious cost consequence, then you need something like this.

Because what -- some of what I've heard from the people, you know, espousing rolled-in, would basically say we don't need LMP either.

I mean, if the goal is to have an unconstrained transmission system where the LMP is the same everywhere, well then we don't need the LMP system; let's just get people building transmission and having transmission rate cases.

MR. KELLY: Mike, just a yes/no question.

(Laughter.)

MR. KELLY: When Dale said that ATC would roll in the rates throughout Wisconsin, and he did a vigorous defense of roll-in, and Wisconsin would pay for it, by and large, is that what you call participant funding?

MR. SCHNITZER: I would not. If the investments are not voluntary, I would not call that participant funding. I think that, and in the tie selection, I agree with Nick, you know, that the voluntary issue is the key issue here.

MR. KELLY: Oh, ATC volunteers to do it. Do individual customers have to volunteer, too?

MR. SCHNITZER: ATC is not a load-serving entity. ATC is an entity which has taxing authority on all of its transmission customers, and there's a real big difference there.

MR. HEGERLE: Nick, do you have a response to what you've just heard?

MR. WINSER: Yes. I just wanted to particularly respond to what Laura said, because I still feel we're confusing two different issues.

None of us -- well, I'm certainly not advocating cross-subsidization, and nor am I advocating whatever the other words were, you know, spread the costs all over every market participant.

The key issue here, and I'll support that by saying, as I said before, I believe the beneficiaries of investment should pay. The key issue is voluntary, pass the hat 'round on assets which are clearly in a lot of cases shared benefit to a lot of different market participants.

In that context, if you pass the hat 'round, lots of people aren't going to put any money in. That's the way it is. That's the classic free rider problem. This is the best example probably in commerce, apart from interstate highways, interestingly, of the free rider problem. That's what we should be discussing here is the voluntary, pass the hat 'round, some people not putting money in, issue, not whether anybody's advocating cross-subsidization.

I firmly would stand against cross-subsidization and have a system of transmission tariffs which allocates the costs to the beneficiaries.

MR. HEGERLE: I know everybody wants to jump in. Hopefully, some of what you'll want to say will appear as we go through this chart.

One thing I heard as a collection of thoughts here was that the system that we have now is not as robust as we need it to be. It's somewhat fragile and doesn't always support customer needs. And what we need to do is find a way to get those things built.

I have asked Roland if he'd be willing to go up to our chart over there. And I'm just going to walk you down. If you turn to the package you have in front of you has the copy of our little chart. I'm just really going to ask for your vote, and your vote might be an either/or between a couple of those boxes. But in the last couple of minutes I have, I'd like to walk through it.

The first category on the matrix here has to do with existing facilities that are already in place. And I think the question is really just saying, are you an advocate of a license plate or a postage stamp, or does it not matter? We'll walk down the row.

MS. BOGORAD: We think that, in an effort to try to deal with the export generation problem, something like a Translink sort of combo license plate/postage stamp is probably the best right way to go.

Having said that, if you pull out a rate based new facilities, you know, new generation facilities don't go into rate-based, then you've got to go into the existing rate base and pull out some of those so there's comparability.

So I think while saying we would support that on the existing, the existing has to then get shaped to be comparable to what you're going to do on new.

MR. HEGERLE: So you'll have it if later on when we get to another one of these categories?

MS. BOGORAD: We don't get to come back to existing.

MR. HEGERLE: Okay. Laura?

MS. MANZ: Zonal rates. And it's important that they get the CRRs for having paid for it.

MR. HEGERLE: Okay. Pete?

MR. MEHRA: I'd say license plates to begin with on a transition to postage stamp rates in the long run.

MR. HEGERLE: Nick?

MR. WINSER: I would agree with that, although I think some sort of regional variation to reflect what's in place currently is a sensible thing here.

MR. HEGERLE: Michael?

MR. SCHNITZER: I agree with Laura. License plate with the CRRs. And there's no need or benefit to reallocating sunk costs. Leave them where they are.

MR. WALTER: I'd say postage stamp.

MR. HEGERLE: Postage stamp.

MR. LANDGREN: I would put in -- again, the default would be the license plate, but I would allow some facilities to be analyzed to be put into the region. And I would just say in terms of this cross-subsidization issue that, as Cynthia pointed out, the existing system has lots of inequities in it. And to only -- to be purer than driven snow on new additions without dealing with the inequities on the existing system is very problematic.

So I think if you're going to talk about not wanting cross-subsidization, you have to talk about the ability of customers to have equal use of the system, which we don't have today.

MR. HEGERLE: I'm realizing that we probably won't have enough time to go through each and every one of these. Some of these I think there's not going to be a whole lot of debate over, while there might be some differences.

So let me jump down to something like upgrades needed for export out of the RTO or ITP. If you're really looking at a situation where a generator knows it wants to leave the area and sell elsewhere, where would you fall on that?

MS. BOGORAD: Well, I guess the first thing is, I would challenge the way you express the question.

MR. HEGERLE: Okay.

MS. BOGORAD: Because especially with what has happened between the line among and between RTOs in the Midwest, saying things are going in and out of RTOs is just not a cognizable concept. And that's really important in trying to set this up.

Because if those boundaries don't mean anything in terms of where the regions are, you really can't use that as a guide to pricing in terms of saying what's a market participant funded thing or not. So that's sort of, step one is, I'm not sure -- I would rewrite your question to say what's going in and out of the region rationally defined, the regional market.

And I would say if the upgrade is not one which is consistent with the regional plan for that region's needs, then it would be a good candidate for participant funding. If it's a major interregional, you know, if it's doing a tie between Georgia and Florida, well, then -- I guess that would be imported to Florida. But at that point, maybe if the regions together decide you need them to make it work, then you'd sort of do it on a more regional basis, maybe allocating it to the whole, one region or in part to the other.

MR. HEGERLE: Fair enough. Let's try a different approach. What would you view as mandatory investments that should be rolled in either -- and let's not distinguish whether it's across the region or a subregion, but what should be done that way?

MS. BOGORAD: Things which are consistent with the regional plan, which is developed to meet the region's needs as articulated in an interactive, open, participatory planning process.

MS. FERNANDEZ: Okay. But in saying that, it should be as part of the regional plan.

MR. HEGERLE: Right. Because I suspect that SeTrans would look at it much differently.

MS. FERNANDEZ: Should the regional plan be simply reliability? Should it include certain ones that are deemed necessary to make the region, increase competition in the region?

MS. BOGORAD: Yes. No, I guess we take the view that the RTO should have an obligation to plan the transmission system to support competitive markets, to support the totality of folks in that market to access, you know, existing generation, new generation through their existing rights and new rights.

I don't mean to be nonresponsive.

MS. FERNANDEZ: No. I think that's fine. Laura?

MS. MANZ: I think the first question that we need to ask is, is the market not able or not willing for some reason to undertake this investment? And so that's the only time you would not have a market-driven solution.

So I would say for as much as you possibly can, use the market signals. And I think we're hearing from a lot of folks that don't have the market signals yet. So, you know, we're kind of in the middle of a transition, and it's a harder conversation to have.

But as we've seen, where you have the market signals, the market is wiling to come forward and offer up a solution.

Where the market hasn't done that, then we're into a regulated or mandated solution. And even in that decision, part of the decision tree -- because I don't look at this as much of a matrix as I look at it as a set of decision trees. When you're in, okay, we've now gotten to the regulated, can we still identify beneficiaries? And if you can, they pay for it. And if you can't, then we're in the other branch of the decision tree, which says as a last resort, it's rolled in.

MS. FERNANDEZ: Okay. But in terms of you can identify beneficiaries, could there be part of the regional plan a requirement to do a network upgrade in a particular subregion?

MS. MANZ: There could be, but it would be based on the reliability criteria for the region. It would be a reliability upgrade.

MS. FERNANDEZ: Okay.

MR. HEGERLE: Pete?

MR. MEHRA: I'd go much further than that. Even if a generator was added to supply load to another RTO, I would say that the additional generation in that RTO in fact does benefit the marketplace and that RTO.

I would in fact have rolled in pricing on that added generation. However, what I would do is, the access charge for all load that leaves the RTO would carry its access charge with it, so to the extent that in fact load does leave that RTO, the fixed costs associated with that load would in fact go with it to the RTO wherever it goes.

And if it's just an RTO in-and-out, you'd get it coming in and you'd get it going out. So the easiest way to do that is to keep it at a rolled-in basis, but let the access charge move with the load going.

MR. HEGERLE: So we would have an inter-RTO charge, an export fee? Yes? Okay. Nick?

MR. WINSER: I agree with Laura's characterization of it actually, that it would be market participant unless there was some sort of backstop process which led to a decision to roll in.

MS. FERNANDEZ: Okay. But from the discussion we had before, I thought your description of the backstop probably would be different than Laura's. I mean, would you limit the backstop to basically reliability-type upgrades?

I mean, if it was a perception that there was an inadequate transmission was causing competitive problems in part of a region, could that get into a regional plan, or would the regional plan basically come down to reliability?

MR. WINSER: Let me just clarify. This is upgrades needed for exports out of RTO?

MS. FERNANDEZ: No. Actually, we ended up going into what should be in the mandatory investments?

MR. WINSER: Would this be mandatory? I wouldn't make it mandatory, no.

MR. HEGERLE: The question was what investments would be mandatory. So if there was a situation where there's a lot of generation here and a lot of load that wants to get at it, can't get at it, you know, and you have to build a line to connect the two, is it rolled in or is it participant-funded?

MS. MANZ: If you have that situation, then the question is, to what extent is someone going to preempt the market signal? There's no right answer.

We're now in a real fuzzy zone that says if you have this, what's going to happen is your prices are going to go up. You're going to have a split. You're going to have congestion. And then the question is, do you want the RTO or the ITP in an invasive role?

Because what they're going to do is they're going to preempt the signal that the market could have provided, and you're going to have this backstopper regulated. And so it's a question of how patient are you, you know, how long you're willing to let the market signals be there to drive investment.

MR. HEGERLE: That's a fair summation of it.

MS. MANZ: And along with that, I worry that if that centralized entity also has sort of a transmission component to their asset base, they may have a tendency to do that preemption because they may benefit.

So I think there's two parts to that.

MR. HEGERLE: That's the question we're asking.

MR. WINSER: And it would come back to I think there should be a separate test to do with the dominance of generation in a particular area, which, you know, we talked about 10, 20, 30, which may in a circumstance where there is very substantial generation seeking to get to a distant market leads to a market participant voluntary-type of system.

MR. HEGERLE: Michael?

MR. SCHNITZER: I think peer reliability investments as I defined them ought to be mandatory and rolled in with some discretion for the ITP to determine whether that's on a beneficiary basis or a zonal basis or exactly how that works, and everything else should be voluntary or participant-funded.

And as to whether that produces enough transmission investment or not enough, I think we have to be very careful about what kind of normative yardstick we're using. The standard of zero congestion is the wrong one. I mean, there is economic levels of congestion. And so if you're basically saying we're underinvesting in transmission, you're saying you know better than the market how much congestion is economic. And I think that's a judgment we should avoid making, unless we have a clear evidence of some kind of failure.

But we should otherwise trust the market is going to make the economic decisions correctly.

MR. HEGERLE: Okay. Ron?

MR. WALTER: What we're focused on here I hope is we're looking for a competitive environment. We're looking for customers to have the choice of their supplier. We're looking for replacement of old transmission and old power plants.

It seems to me that the idea of an independent entity that doesn't have a vested interest like an ITP should be able to use those principles as a guideline to decide which upgrades ought to be done and then roll them in.

MS. FERNANDEZ: So you wouldn't limit that ITP to only reliability upgrades? You'd give them some flexibility to include other ones you would think would benefit the market in the region?

MR. WALTER: To improve competition, yes.

MS. FERNANDEZ: Okay.

MR. HEGERLE: Dale?

MR. LANDGREN: I would put them in the mandatory regional postage stamp. Again, our view is that because of the multiple purposes of lines, we do think that there's a value for most facilities in the region.

We also have trouble seeing that market signals will drive enough investment, particularly in the short term. And I think we're seeing now that market signals don't always cause generation to be built when there's financing problems. And I think you can see the same kind of thing happening if transmission is dependent on market signals, that it isn't always going to get built because people have to respond to other financial imperatives beyond just the market signal.

MR. HEGERLE: Thank you. Let me ask if there's any closing questions from the Commissioners before we end this panel.

COMMISSIONER BROWNELL: I think there was some consistency, as you pointed out, Mark, that this existing infrastructure is inadequate in almost every way. And it would be helpful I think to hear from the customer side as well as others about experiences you've had, because it might help us focus in on some of these solutions. So to the extent, Pete, that you wanted to add to your comments, you'd get those to us in writing.

Ron, those specific things that you want to get to, I think that would be helpful too.

Cindy, that would be terrifically helpful. Because I think we operate under the misconception that the system we have today is adequate to serve future economic growth, and it's pretty clear it's not.

CHAIRMAN WOOD: I was a bit intrigued, I think, Pete, from your I think crystallization of something that's been bugging me for a while as we think through some of the more extreme examples as I think folks in Entergy know with Louisiana and the overbuild there.

Fixing the export problem could be two different -- you could probably do that two different ways. I'm a little worried that we would do it both ways, both ways being participant-funded and put an expert fee on it. Because that really socks the end-use customer twice by paying basically the embedded charges of, say, SeTrans, and the participant funding in the local region where they upgraded the grid.

Is there a preferred solution to address the export problem, which seems particularly to be pronounced for the Southeast perhaps and maybe in other regions? Do you fix that one way or the other? I think our first witness would I assume say participant-funded. But would you also have an export fee on top of that? Or would you just do an export fee only and kind of lean toward rolling in, as I think Pete was saying?

If y'all can just kind of quickly without more than one-sentence answers zoom down. I want to hear from a different perspective.

MS. BOGORAD: Well, as I said before, our preferred fix is, if you want to call it export fee -- that's not exactly the way we'd frame it. But I think the Translink proposal is that the generators pay a fee in the zones where they are, even if they're going to another RTO or to another zone.

So that's effectively a partial export fee. And that's the way we would do it rather than going through this participant funding.

MS. MANZ: The problem I think we're trying to solve is to make sure we get the embedded cost of the grid recovered. And so that's what we're trying to do.

And we can either do that through a license plate fee. We've done it in PJM with the license plate rates, and through-and-out rates, so you can have a little bit of both.

And so I think that's what we're trying to do is just make sure that in total we're trying to collect the embedded costs and make sure that we have cost recovery for the transmission grid.

CHAIRMAN WOOD: But do you recover that through the participant funding, which we already have going in PJM, for that generator that is paying two-thirds of the $700 million that's being built right now? And then his transaction would also bear a through-and-out export rate to be sold into, say, Kentucky or Virginia?

MS. MANZ: I think we're talking about old funding, which is what's already there. How do we recover that? And that we need to figure out through the license plate rate, through a through-and-out rate, how we'd recover that embedded cost.

If we go to markets and someone's truly receiving a market benefit from exporting, I would advocate that it's on their nickel that this new export be done, because they are the beneficiaries of that export.

CHAIRMAN WOOD: But do you --

MS. MANZ: And then it wouldn't go into either the network -- it wouldn't go into the network access fee.

CHAIRMAN WOOD: So it would not go into a direct bill as a participant funding? It would just go straight into the export fund?

MS. MANZ: It would be somehow in the contract. And so this is the shift, when we start talking about market-driven expansion. And again, I'm talking that we have recovered the embedded costs of the grid through that access fee.

And now we're looking at how do you fund future investment. If you have a future economic investment, it's the beneficiary that should be funding that investment, and the costs are recovered through their contract and not through an access fee.

CHAIRMAN WOOD: But that ties back to how, I mean, you can't divorce the old and the new totally.

MS. MANZ: That's right.

CHAIRMAN WOOD: You've got to say that the right allocation of the old has got to have some bearing to where you are with the whole agenda.

MS. MANZ: Right.

CHAIRMAN WOOD: Are you putting some on the export there as well?

MS. MANZ: I'm a little confused between the export you're describing. Is that a new upgrade for new export?

CHAIRMAN WOOD: Yes. There's a generator in PJM. He's selling into Virginia.

MS. MANZ: Okay. Then that new upgrade to do an economic export would be funded by the generator and recovered through the contract.

CHAIRMAN WOOD: Would there continue to be an export fee for the existing cost of PJM transmission that is also assessed on his transaction into Virginia?

MS. MANZ: We do that now.

CHAIRMAN WOOD: Is that what we should have going forward?

MS. MANZ: It would help.

CHAIRMAN WOOD: And you would say that no, correct?

MR. MEHRA: I would say that you'd do it not with an export fee, but I'd call it an access charge, which is the same that's paid by everybody.

My biggest problem is that I don't think you can start off by the definition saying, is this a load for a generator for export? I think most generation is going to be built and it's going to benefit both the local RTO as well as it ends up. And in fact, the generator that may be built today to export to up north today may tomorrow start selling in the local market.

Contracts may be short-term, long-term. They may change. People may get out of contracts. You've got all sorts of things.

CHAIRMAN WOOD: Let me follow up on that. Then so if that generator got sent a bill for the $50 million of upgrade cost to do that export today, but five years from now he's selling into the area because all the old stuff shut down, which might be an issue in the South as well, but today you might be shipping to TVA, but tomorrow you might be selling down the street, you've already socked a bunch of costs now for that export for the front end of your years, and you're really stuck with that and you don't need it anymore.

Mr. MEHRA: That's why I wouldn't charge them the $50 million. I would charge them, if next year they exported 100 megawatts of load, whatever the fixed costs associated with 100 megawatts of load is the access charge is what they paid.

And so, to the extent you keep exporting it, you keep paying for the local usage of the facilities, to the extent you stop exporting and selling it local, you're paying just the local charges.

MR. WINSER: We would propose to in general roll those costs in, although some sophistication on postage stamp or license plates to identify the beneficiaries would seem to us to be the right thing.

In circumstances where there is a profound excess of generation that was seeking access to new markets some distance away, we would make an exception of that, and if you like in your terminology, charge the generators an export fee to recognize that those facilities that are being built to connect them to market are predominately to the benefit of those generators.

CHAIRMAN WOOD: Mike?

MR. SCHNITZER: I think it's helpful to make sure that we're in an LMP financial rights world when we're answering this question as opposed to a physical rights world.

And so I think when someone is investing for exports, what they're investing is to create more CRRs between one region and another. And so I think that in the SeTrans proposals, yes, that whoever it is that wanted those CRRs, who wanted to hedge -- because without the hedges, they could still schedule. They'd just have to pay congestion, right?

So it's not that they were physically prevented from scheduling. So what they're investing in is to hedge the congestion between their point of injection and their sale point. And we would say that should be participant funded.

Now as to whether the should also pay an embedded cost exit fee, I think in the SeTrans proposal, you have an out-and-through rate proposal that is designed at a minimum to collect the lost revenues from lost pancaking.

So I think you have a policy choice here as to when you go to broader regions, you know, and you eliminating pancaking, what do you do with the cost shifts that would otherwise result from that? You have one proposal for SeTrans is to allow out-and-through service to make up that revenue. And perhaps the answer to your question would be different, depending on whether you'd covered your lost revenue or you hadn't yet.

But I think that's the basic policy question on the sunk costs in the existing system is, do you want to leave that recovery more or less where it is, or do you want to allow it to shift back to other customers?

But independent of that, in a financial rights world, the person who wants those rights should pay for them. And in the example where five years later they turn around and decide to sell locally, they still have the financial rights. They still have the CRRs. That's why we can't think physical rights. They didn't lose anything. They can sell to ta local utility and still get paid off on the CRRs between regions or sell those to somebody else.

Today when they change their service, they do lose the benefit of the investment. That's why the OATT doesn't work as well as standard market design with participant funding will.

MR. WALTER: In our view, if you are able to access more markets, and if there are investments that allow you do so, that we think a participant-server arrangement would work.

But I think that in our case, if we have a power plant -- and, by the way, most of the power plants we site are sited to meet native load kind of situations. That seems to be the best way to work in a system where the transmission grid is not all that reliable.

But we would very much, in an ideal world, like to be able to move one, two, or three markets to access customers who we want to serve and they want us as their providers, so we would be willing to pay for that ability to do so, but we would need, you know, the CRRs or whatever you have, or the firm transmission rights or whatever comes with it, to allow us to be able to continue to serve that customer if we want to go out of a region into another region.

MR. LANDGREN: We would not propose an export fee. We would not have a through-and-out rate between RTOs.

As I mentioned before, we would look at a specific facility. If it's within the RTO, you could do an allocation based on power flows in terms of which zones it benefits.

If it's between RTOs, the two RTOs can assess 60 percent of this line really brings benefit to this RTO, and you can sign that and have a regional access charge.

But we think that if you look at the facilities and have the RTOs divide up their usage, there is no lost revenues; you are just reconfiguring how you collect the money for it, so you don't need an exit fee, you don't need any through-and-out or any lost revenue calculation.

COMMISSIONER MASSEY: When I look at this issue, I look at it in the context of what I consider to be the centerpiece of standard market design, which is locational marginal pricing.

It seems to me that all the working parts of standard market design ought to fit together in some cohesive way. And if we are -- if the centerpiece is locational marginal pricing, it seems to me that some sort of participant funding is more consistent with that.

And so I would ask Dale. I mean, you stand for more of a roll-in philosophy, and I would ask you to tell me how is the philosophy of rolling in, more consistent with locational marginal pricing, which seems to me to me to be more of a marginal cost approach? How is it more consistent than some sort of participant funding?

MR. LANDGREN: Well, I would start out with the higher goal, which is to make the wholesale energy market competitive. The notion that LMP will help you to do that, I agree with, but to me, you're looking at what do you need to do in order to make the wholesale electricity market competitive?

LMP is an effective pricing mechanism to price short-term congestion. In our view, it doesn't really tell you that much, longer-term, about what kind of new facilities are built. It's a way to price a scarce commodity in the short term.

So it's very -- LMP is very consistent with the fact that you have a scarce good and you need to figure out an efficient way to allocate it. We don't believe that it's going to tell you, long term, what kind of facilities need to get built.

So from that perspective, and for the reasons I gave before to FERC Staff, because of the fact that situations change over time, the fact that facilities have multiple uses, the fact that you can't really predict when generation is going to be in or out or if load is going to grow, we think that, really, transmission planning needs to be more from a total infrastructure perspective, which means it has -- it's a social good; it's a public good; it's very hard to associate property rights with it, and we think it should be planned that way, and, therefore, paid by all the people who use the system, which is the rolled-in philosophy.

MS. BOGORAD: I agree with what he said, and I would just add one thing, is that there is a tension there; you're right. But on the other hand, I think it's a question of how we get from here to there.

Maybe once we get the basic highway system in that can support competition, then maybe we can lean more heavily on that. But we're so far from that now that that's sort of out there in the wilderness, and so to use that as the method to get the basic substructure in, means we'll never get there.

MR. HEGERLE: I'm going to let Nick speak, and then I think we need to draw this one to a close, so we can get the next panel here.

MR. WINSER: I wouldn't particularly say that one is more appropriate or better fit for LMP than the other. I would highlight that LMP is a very sensible mechanism for, as Dale said, pricing short-term congestion, but it will highlight that congestion and it will emphasize that congestion and make the economic effects of it quite large.

And, therefore, I would argue that a system which may lead to under-investment in transmission, because of its voluntary nature and the free right of problems, could well be a real poison to an LMP market.

MR. HEGERLE: Anything else?

(No response.)

CHAIRMAN WOOD: I want to thank our panel for coming today. It was a great kickoff, and I just think that raises the bar for the next three.

MR. HEGERLE: Thank you very much. We're going to take a five-minute break and get started right away to get us back on track.

(Recess.)

MR. HEGERLE: We'll start with the next panel, when we get going here in front of me. I think we can go ahead and start here.

I think we learned a few things in our first panel. As we summed up a little bit the last time, we learned that the grid does need some work. It's a little bit fragile from meeting all the demands of the customers that are there, and we need to find a way to get the facilities built.

I think we also ruled out the fact that nobody is really in favor of everything being participant-funded, and nobody is really in favor of everything being rolled in. We're somewhere in the middle of those two extremes.

And I think we have identified a fairly central question that we have written on the flip chart over there, and that is pretty much what investments should fall under the mandatory rolled-in pricing? You know, these are these economic investments to get rid of load pockets or are they just for the highway system that we need to move power from region to region or even within a region to facilitate competitive markets?

And I think that we're going to try to focus on that central question as a way of making some progress today. The other thing that I observed is that we had some panelists that were very patient and ended up waiting almost 45 minutes before they got to turn their microphone on.

So while I instructed all the panelists ahead of time that we would not have opening statements, per se, where you have a presentation, I know that many of you, if not all of you, have submitted at least a one- or two-pager describing where your company comes out on the topic of today.

And I was wondering if each of you could take literally a minute or two and just sort of walk us through your views, perhaps focusing on that question, so that we can derive a little debate on that very question over there? And if you'd introduce yourselves as you speak?

MR. McKINNON: My name is Bill McKinnon, and I'm from Northeast Utilities. First of all, I'd like to thank you for this opportunity to speak today.

Again, we believe that the real goal of transmission is to enable a competitive market, in that terms of trying to answer the question today, we think you have to look at both parts of the planning process, as well as the pricing process, and that they're married together.

Certainly in the Northeast, we believe that New England is different than other parts of the country in many key aspects. We have implemented parts of Order 2000 and proposed SMD NOPR, and particularly in the areas where we've divested our generation. We have implemented an ISO.

We have an independent regional transmission expansion plan that in its second version. We're moving to LMP with FTR.

And under this basis, I want to try to answer how I think it's working in New England, and why I think I can get to the answer to your question.

The planning process has three parts to it, and the first part is, the ISO, which probably has more information on the market than anyone else, publishes a regional plan that's open for comment, available to all, and not finalized until input has been received.

So at this point I think that we're providing information on all the regional needs, whether they are reliability or economic to the full marketplace.

And then the second part of that project is -- second part of that planning process is that the ISO asked for a response from the market. Now, I think this is where some of the economic projects we're talking about how do you pay for them, start to get weeded out, because there's a period where the market has an opportunity to respond and to put forward to the ISO, its solutions to the problems that have been identified regionally by an independent body.

Transmission owners, basically building cost-based transmission, can also propose answers, but it's not until the ISO endorses the transmission owners to build those projects that they move forward. In fact, the transmission owners would have an obligation to build.

In this model, we're not looking at -- once the ISO endorses the construction of a transmission project based on the fact that the market has failed to respond to a published need, we don't see the need to differentiate whether it's economic or reliability. It is, in essence, a needed resource that we have an obligation to build as a provider of first resort.

What I mean by that is that I think it should be built by the transmission companies to avoid right-of-way debates, issues around eminent domain, which are state-by-state, and many of the restrictions placed on our right-of-ways by the landowners which we've negotiated with over years and years.

The point is that this is the most efficient and quickest way to get the projects that the ISO has identified need being built, to be built, to ensure that the costs in that process would be managed, and our RFP process for construction would be administered by the ISO, particularly if the transmission company or any of its affiliates intended to bid on the process.

If they didn't intend to bid, then the ISO could sort of do a quality assurance and watch the transmission company manage the RFP. Again, this would be a level playing field, ensuring that new technologies would be brought into the process.

And it is finally at this point that we think that a beneficial test -- and I guess I'm shifting from the planning process now to the pricing structure -- again, if we look at New England, we believe we have a beneficial test.

It's not necessarily license-plate, nor is it postage-stamp; rather, it's a hybrid, sort of a tiered approach where with a minimal voltage and a functional design, assets are classified as either benefitting the region or assets are classified as benefitting only a local area.

In this process of defining a minimal voltage and a functional design, stakeholders have an opportunity to participate. We call it 15-5 in our NEPOOL process, and there is active debate as to whether the clearly-defined rules are being applied consistently for each new project.

If we look at where ISO New England and New York ISO propose in their nodal proposal in terms of a pricing structure, they instituted a third tier or proposed a third tier which would be any 345 project in New York or New England that would be across a super-region.

And although that's not obviously a current reality, it's the concept of it doesn't have to be license-plate or socialized, but, indeed, it could be a beneficial tiered test, which I believe is what New England is using today.

Again, I have been speaking mostly of transmission that would need to be built for reliability needs or market growth. Obviously, we do have to build transmission to interconnect generators.

Again, I think New England is a bit unique. We have a minimal interconnection standard. Since November of 1998, for the last four years, every generator has requested interconnection under that minimal interconnection standard. An enhanced standard is also available.

Commenting on the previous panel, if we had a 10,000-heat rate old plant and a 7,000-heat rate new plant, under the minimal interconnection standards today, if they wanted to locate side-by-side, they would do that with minimal cost, and, indeed, the two plants would compete.

One would run, or perhaps the reality of it is that one and a half of the two plants would run, based on the fact that the current plant is already there, the old plant, and the new plant coming in at the same size would compete with it, and to the degree that the system really had some fat in it or some excess in it, you might find one and a half plants running, versus two.

So under that basis, today, if people ask for the minimal interconnection standard, we believe it's appropriate that they also pay through-and-out rates when they try to go to other regions, because they haven't really paid to be fully interconnected to the system.

If a generator paid for the enhanced service, where they would be fully interconnected to the system, then we would grant them CRRs or, indeed, think differently about it. But, as I said, for the last four years, every single interconnection in New England has been asked for under minimal interconnection standard.

So, I guess, in summary, we think that we need to have simple rules that do embrace beneficial tests; that those rules can be a hybrid structure; that New England has gone a long way toward adopting that. The NERDO proposal by New York and New England embraces that and takes it further.

And that there should be some flexibility in the Commission's ruling as we go forward, to realize that all parts of the region are in different places with different histories, and that New England may be a bit different than others in where it's been over the last 30 years with a tight power pool.

MR. HEGERLE: I think what we'll do is just go down the row and we'll start the questioning after everyone gets a chance to speak. Jacob?

MR. WILLIAMS: My name is Jacob Williams, and I'm Vice President with Peabody Energy.

The goal of electric service and the goal of regulation of electric service is to provide both affordable -- and I emphasize affordable -- and reliable electricity, and price does matter, and it's an important part of the regulation that goes on.

The reason we have low-cost electricity in the United States, pure and simple, is that in some regions we're blessed with the hydro resource and in the other regions, it's coal-based generation.

And if you look at the price disparities between regions and in places, it's because low-cost generation, low variable cost generation is generally trapped from getting at areas that have higher cost.

You can look at it especially in the wholesale market in the on- and off-peak prices. You can see it between the Midwest and the Northeast, a tripling of off-peak prices in the middle of the night, all because the coal generation cannot get to the Northeast. The excess is sitting there -- not new units, but existing excess.

The same thing occurs in Florida, for example, in some areas of the Southeast and Southwest. That's today. The dilemma for us is, over the next ten years, those disparities are going to grow much larger if we don't build transmission, because there are certainly going to be areas that, quite frankly, will not have access to the low-cost generation sources that are out there.

And I agree with the statements from the first panel; that if you think about transmission being such a relatively small piece of the puzzle in terms of pricing, and yet, from an overall price to have affordable electricity, it drives the ball game.

We are best not to come up short on transmission. Market power views things of that nature as a function of having limited transmission out there, and so any market proposal needs to err on the side of adequate, not only reliability reserves, but affordability reserves, so that we can withstand weather events.

In our C-pronouncements about nuclear units, fuel prices changes because we can't build transmission quick enough to solve those issues.

Now, the other thing to think about is, if we were to try to build the U.S. highway system with the current method of participant funding, we would have never built the U.S. Interstate system. You couldn't go to GM, Ford, or Chrysler, and say pay for all the extra highway upgrades, because you're really the ones that are producing the cars that move down the road. It would not work.

If you think about consumer benefits, most of the upgrades that we talk about here are really to benefit the consumers, and a planning process should be in place to look at, are the upgrades that are required, going to benefit the consumers?

If they are, a rolled-in type of pricing is a reasonable way. If, through the planning process, it's deemed these upgrades are really to serve generation interconnection, that should be strictly a participant funding, or in some cases, maybe it was an inordinate amount of generation showed up in a very small area, and frankly, the customers throughout the region aren't going to benefit if that generation is freed up, that, too, could be participant funding. I've got no problem with that.

But solving some of the major bottlenecks that are out there, generators -- new generators didn't cause the bottlenecks up into the Northeast. It is the way it is, and so which generator can you hang that on?

It's the participants or it's all the customers in that Northeast who would benefit from solving those. So, for the most part, most of the upgrades really are more on a rolled-in basis than they are for a very specific set of generators.

Finally, maybe after we've solved the lack of infrastructure issue, we can move more to participant funding on merchant lines. The problem with that is, when you build a merchant line, you decrease the LMP differential between two points, so the value that you're trying to capture is gone and the customer has actually received the benefit, because prices went down on the constrained end.

I'm not sure how you fund solving major infrastructure bottlenecks through participant funding when there's not one generator that's causing the problem.

MR. O'NEILL: Do the generators benefit at all?

MR. WILLIAMS: The generators may benefit a little bit more, but, frankly, it's all the customers on the other end whose total market price goes down, that will benefit far more.

MR. O'NEILL: And your market price won't go up?

MR. WILLIAMS: Our market price may go up some that's right. But the goal is to decrease customer -- to have affordable electricity and decrease market prices.

MR. HEGERLE: Frank?

MR. SCHILLER: Thank you, Mark. I'm Frank

Schiller; I'm with Progress Energy. Progress Energy encompasses two vertically-integrated utilities and a fairly active merchant plant generation subsidiary, so as you can imagine, we have some fairly lively debates, internally, about some of these issues from a policy perspective.

One of the challenges with talking about participant funding is that if you talk to different people, they will all tell you, well, I'm in favor of participant funding, and then when you ask them what participant funding is, they're 180 degrees away from each other.

MR. HEGERLE: That's why we're here today.

MR. SCHILLER: So in order to try to just tell you what I think of participant funding, it's generally any methodology that allocates cost of new transmission facilities and upgrades, according to who is benefitted the most by the investment.

If a load-serving entity or a generator is benefitting, particularly from a proposed transmission addition, we believe that the costs should be allocated to that entity and should recognize the exceptional level of benefit.

However, that does not mean that most transmission upgrades should be, at the end of the day, funded in that way. To the contrary, our view is that except in unusual circumstances, the majority of transmission costs should be rolled in to an overall transmission rate base.

You know, one could argue that the traditional way of rolling in transmission costs has been participant funding in some sense. If you look back traditionally, traditionally, transmission systems, and, indeed, electric systems were built primarily for the benefit of local native load. Therefore, it made sense to roll it in, because it was being assigned to local native load.

So, participant funding is not, at least in our view, that much of a break with the past. The question is, though, how are you going to devise a policy that sends the right signals for efficient upgrades and use of the system and it does not unfairly burden a particular entity or an industry sector and can be applied evenhandedly in all regions, regardless of the market design.

That is not so easy. Our thought is, at least at this stage, that the Commission was somewhat on the right track, we think, with the generation interconnection ANOPR and the concepts that were set forth in there.

The core principles, at least as I understood them, of that concept was that a participant desiring a particular service funds the transmission upgrades needed to accommodate the requests and then second, as transmission service is taken, reimbursement would be provided to the funding party. So it is an up-front funding as opposed to a permanent cost shifting.

This approach shifts the obligation and risks of the requested transmission improvements to the entity that benefits, but it also provides a return of that up-front funding as the transmission becomes used and useful. And indeed, that's really what you're doing. You're using the use of the transmission service as your best proxy for when it made sense or how much it made sense to invest in that transmission.

We think that that mechanism -- and I'll call it participant funding, although it ultimately arguably leads to a roll-in at the end of the day -- that was being developed as part of the generation interconnection process could be applied in current markets. It could be applied in future markets. The concepts can be applied to generation interconnection but could also beyond generation interconnection.

Our thought was that the Commission was making some pretty good progress towards making that a workable format to resolve this issue, and resolve it in a way that didn't necessarily depend upon trying to parse out which individual entity benefits from which individual upgrade.

We think that transmission systems ought to be viewed as a single machine, and it's hard, particularly over time, to say you're going to benefit and you're going to be the sole beneficiary of a particular upgrade.

You can say at the beginning when someone is requesting service, and that is causing cost to be incurred, that you should take the risk of funding that up front, and if you make the right decision and actually use the transmission as requested, then you will actually receive the money back, and if not, you have made a bad bet on that transmission.

We would think that -- we would hope that the Commission will get back to that process, get back to those policies. They do need to be further vetted, defined, refined, but we think they provide a basis for resolving some of these issues.

MR. HEGERLE: Jose?

MR. ROTGER: Thank you, Mark, and thank you for the opportunity to speak today. My name is Jose Rotger. I am the Director of Regulatory Policy for TransEnergie U.S. And many of you know me as probably sometimes the only fellow out there that's talking about merchant transmission and the competitive nature of the transmission business.

But today, I'm going to be focusing on something a little different, perhaps uncharacteristically so. What we would like to talk about is what I'm going to call the ITP plan or regulated transmission that we see coming out of the SMD NOPR and the planning regime. I realize this is not a planning seminar, and I will try not to talk about that.

But in general, we did submit a proposal, and I won't go into it, because a lot of it in fact has been more eloquently stated by Mike Schnitzer earlier this morning in his chart. We very much support his framework, this flowchart, and his or Entergy's SeTrans -- sorry. Too many names -- their interpretation of what types of investments should be funded in what manner.

In our proposal, we talk about effectively two vehicles for the pricing of these ITP-planned transmission upgrades. We emphasize the need for license plate rates because we believe that license plate rates ultimately is consistent with an LMP system.

But we also talk about certain projects that may require a more regional approach. And for those projects we would advocate a regional postage stamp-type rate. And in fact, probably the initial example of that would be the type of monies that would have to flow across the various ITPs in order for each transmission owner to be held harmless upon the elimination of export or outservice. That type of postage stamp rate could be used as a vehicle for that type of allocation.

In terms of Staff's or the Commission's chart, I'm not going to go through it, but I will suggest that at least the participant funding column needs to be segregated into two columns. One is a mandatory participant funding, and one is a voluntary participant funding. I think we saw some of that today. Because the answer is different if you have one or the other.

Finally, in our presentation or filing which I realize I hope the Commission has, but I'm not sure the folks behind me have.

MR. HEGERLE: The Commissioners and Staff certainly do.

MR. ROTGER: Thank you, Mark. We've got to figure on placing the ITP in the middle of this flow of funds depiction. And the purpose of this slide was to illustrate how if you have an ITP serving as a clearinghouse for various types of investments, having on the extreme right-hand side you have various license plate rates being collected by the ITP as well as a regional postage stamp rolled-in rate. And then the ITP making sure that the various independent transmission companies, which by the way I consider myself to be one, whether they're a new entrant ITC or an existing incumbent ITC, as well as the funds involved in making sure that the outservice elimination is revenue-neutral, so to speak.

We have the ITP sitting in the middle of this flow of funds and making sure that things get done appropriately.

Once you have this framework, if you think it through, you very quickly realize that this is the entity that does the planning and this is the entity that's in charge of looking out for the system.

That's it. I'm hoping to get lots of questions. Thank you.

MR. HEGERLE: John?

MR. HOWE: Thanks very much. John Howe with American Superconductor. I want to strongly encourage the Commission right at the outset to continue with implementation of standard market design, particularly locational marginal pricing, the centerpiece. It really is I think the answer to foster competitive markets.

And I'm here today to say that I believe transmission should be looked upon as a profitable business opportunity. If we get the market structure right, I believe we're going to see companies coming forward to seek out opportunities to compete in transmission just as we've seen in every other network-based industry.

I think, though, that we need to be candid. Politically, it's going to be very difficult to get consensus to support rolled-in ratemaking for major new long-line facilities, and there's also the gorilla in the room, which is the difficulty of siting major new long-line facilities.

And I am afraid that we're going to get sidetracked for a number of years with discussions and debates as long as we continue to focus on traditional solutions.

There are a lot of things that can be done with the existing grid immediately or in a matter of a few months as opposed to five to ten years to enhance the performance of the system. The fact is that many power lines in this country operate at a fraction of their full thermal potential because of voltage and angular stability limitations. And there's a range of solutions.

Our company is involved, other companies are involved, market leaders like ABB and Mitsubishi as well as American Superconductor, offering solutions that can enhance the voltage stability of the existing system in order to allow that thermal potential to be more fully utilized.

This is the low-hanging fruit, by far the cheapest transmission capacity that's available. We have superconducting storage systems on grids today that allow increased delivery of as much as 60, 80, even 100 megawatts of additional capacity over existing lines for a price tag of about $2 million, literally a nickel on the dollar compared to the cost of building new generation.

Our problem is, we've used the analogy of the highway. In some ways, we've built the office parks and factories before we built the highway and the cloverleafs and the off-ramps in order to allow those new facilities to get onto the ramp.

We need to send the locational price signals to encourage generators to locate in the right places, but we also have to figure out a way to enable the existing sunk stranded generation investment, tens of billions of dollars, to find broader markets, and we need to do it soon, or else we're going to have widespread business failures, which is not going to be good for the country's economy.

In my proposal, which I've circulated to the Commission, I've set forth a few guidelines on how we could foster I think a more robust market opportunity for some of these smaller scale, rapidly deployable and mobile transmission solutions. That's one of the nice things about these devices is you can roll them into a substation, increase the voltage stability, allow increased transfer. And then if the need goes away in a couple of years because a new generator has been located, these units, this equipment can be relocated at other sites.

So it seems to be ideally suited for an environment in which we're going to have economically driven retirements and sudden gaps appearing in the transmission system. We really need to broaden the range of potential solutions.

In terms of dealing with the issue of rolled-in pricing, I would just close with one final comment, which is, as a veteran, years ago in my career in the IPP industry, as a veteran of the rolled-in versus incremental ratemaking wars in the pipeline industry, I do recall how every three years we would go up against the pipeline and argue that our facilities should be rolled in, and there was a determination, no, they should stay incremental. And then ultimately, the facilities were rolled in after a certain period of time.

Perhaps an approach the Commission might entertain would be to allow those market participants who see a business opportunity to build a transmission upgrade to put up the capital, to gain the congestion revenue rights or structure businesses around the congestion, which is likely to be most acute and most identifiable in the early years that those facilities are in service. And then at some point in time -- it might be three to five or five to seven years after the facilities are in service -- when they meet a certain test, they would be rolled into the system. The original investment would be cashed out, and the rates would be rolled into system rates.

But we must not allow the hang-up over these ratemaking questions to deter the kinds of investments that can be made quickly to enhance and restore the value of our transmission system.

Thanks.

MR. GROSS: My name is Bob Gross, and I'm here on behalf of the East Texas Cooperatives, and we certainly appreciate the opportunity to participate in this quorum.

The East Texas Cooperatives I guess bring a view of the transmission-dependent utility, small load-serving entity. They are located in the non-ERCOT portions of Texas, in East Texas. There are four GNTs there who have been very active for the last 15 to 20 years in the wholesale power market. And I think we bring a perspective that we'd like to share with everybody as far as what's really going on out there in the market today that has an impact on what we are doing here as far as trying to set up a market that will encourage competition rather than discourage it.

There are certain things about the participant funding application that we are very concerned about. As a lead-in to get to that concern, I think it would help if we described a little bit about our situation and what we're up to.

The cooperatives in East Texas, as I said, have been at this business for a number of years. They were probably one of the first wholesale groups to access the competitive wholesale markets in this country. They also were one of the first to use the open access tariffs to do so. So they've been on the forefront of this movement toward more deregulated markets. And they're at a point right now where we're trying to make decisions with regard to what kind of alternatives, what kind of opportunities exist in the more competitive markets hopefully that will exist in the future.

As we do that, we're running into a situation where as we rotate through resources, cooperatives typically what they do as far as their bulk power supply needs, they are changing from time to time their supply portfolios. They do this because they have to in most cases. They have contracts that come up for renewal or they terminate. And this fellow who sold you requirements power in the past may not be interested in doing that in the future, and therefore the cooperatives are faced in some cases with going back to the market looking for substitutes.

What we're finding in the market today is that in looking for those substitutes, we are having to designate new network resources. In doing that, that's triggering in some cases transmission impact studies that have very significant price tags in order to access resources that in some cases have been generating resources on the system for years.

Our impression is one that in the past, transmission issues were not a major component of the decisionmaking process. Now they are almost 90 percent of the process, trying to vet wholesale resource opportunities. Ninety percent of that is tied up with transmission requests, evaluating the transmission problems that are attendant with those requests, and trying to sort through this whole process in order to determine if you've got a viable firm resource that you can depend on.

So one of the things that we're most concerned about is as the more what I would call diabolical forms of participant funding are defined, and that is leaning heavily to this more voluntary default mechanism where everything falls into participant funding and you have a very narrow band that is rolled in for reliability purposes, that groups like these Texas cooperatives are going to be put on the margin and are going to be placed in a position where large transmission upgrades may be triggered, which will prevent them from being able to access resources that are out there on the marketplace. And thus, the marketplace will contract, from our perspective.

What we're looking for I think is a reasonable access to the marketplace. There are a lot of players out there. We feel like there are a lot of opportunities. But transmission considerations are a major, major problem right now in trying to determine how to go forward.

So in a nutshell, what we would like to see is more of a rolled in approach as to erring on the side of rolled in rather than a strict beneficiaries test under a participant funding doctrine.

MR. HEGERLE: Thank you. Bruce?

MR. EDELSTON: Thank you. My name is Bruce Edelston. I work for a small little utility in the Southeast called Southern Company.

I want to start out first of all to say Southern is a member of SeTrans, and we support everything that Michael Schnitzer said this morning. I hope the fact that you invited two SeTrans speakers means that we get two votes on your chart.

(Laughter.)

MR. HEGERLE: We'll grant you that.

MR. EDELSTON: Okay. I want to start out with my own definition of participant funding, because I think it does differ a little from what Frank said and what others have said. My definition of participant funding is that those who pay for transmission upgrades get the benefits.

And that's subtley different from the other definitions because participant funding in my mind is not a way of allocating benefits and costs before or after the fact. Rather, it's simply a way of ensuring that whoever pays for transmission upgrades gets the benefits from the upgrades that they paid for in the form of FTRs or congestion revenue rights or whatever you want to call them. I think that's very important.

I do want to make a few other points since I have the opportunity in response to some of the things that I've heard today and on the first panel as well. If there's one thing I could do today is to urge, beg, cajole, do anything I can to get people off of this notion that because only five percent of transmission costs or five percent of power costs are due to transmission that transmission doesn't matter and we should simply build as much transmission as we can to get competitive generation markets.

First of all, it's untrue, and second of all, it's irrelevant. It's untrue because when deciding what we're doing going forward, we need to look at marginal costs and not embedded costs and that five percent is an historical embedded cost.

Going forward, we can point to many projects in our system and around the country where the marginal costs of building transmission actually exceed the costs of the generation on a per kilowatt or per megawatt basis. So looking at historical cost versus marginal cost is the first point I want to make.

It's irrelevant because when we talk about competition, we're not talking just about competition in generation. We're talking about competition for power delivered to the customer. After all, it's the customer who we want to provide the savings for. Therefore, one needs to take into account both generation and transmission costs in developing an efficient power market.

And efficiency demands that customers face the true costs of their purchase decisions, and those true costs include both generation and transmission costs.

That gets me to the second point I want to make, and this is in response to Commissioner Massey's question, is that without participant funding, I strongly believe that locational marginal pricing and market-based congestion will fail. And the reason I believe that is that if in my decision as a customer I can be assured or I can predict that somebody else is going to pay the cost of relieving congestion as a result of my location decision, then I'll locate anywhere, because I don't have to face the cost of my location decision.

Or even with respect to my use decisions, if I'm located in a congested area and if somebody else is willing to pay the cost of relieving the congestion, then why wouldn't I continue to use more power int hat area even though that's not the most efficient solution?

I would also add that participant funding is more consistent with the use of demand-side management, distributed generation. And also I think it's very important to get the kind of technologies that John Howe talked about in that we have to continue to provide the right signals, the right price signals to get those technologies developed. And if we socialize cost, if we roll in cost, again, we're providing everybody with the wrong price signals.

The third point is I'd urge the Commission to be wary of those who want their investments rolled in but want everyone else's investment participant funded. We think that all investments have to be treated the same. Reliability investments, and I think Mike Schnitzer this morning gave the definition of what we consider to be reliability investments, should be rolled in on a sub-zonal zonal, or regional basis, depending on where the benefits lie. But all other investments should be participant funded.

If Southern Company needs to make a transmission investment to provide service or designate a new network resource for our native load, we should be required to participant fund those investments just as anybody else should be required to participant fund their investments.

Fourth point. We cannot optimally plan the transmission system any longer, and we should not try and pretend that we can.

Optimal transmission planning requires the minimization of the costs of transmission and generation taken together, but on one entity today is making both transmission and generation decisions.

The best we can do is put the right price signals in place so that there are economic incentives for minimizing total cost. And the only way to do this, again, is to ensure that those making decisions either for purchasing power, selling power, or locating generation, face the true costs of their decisions. That's exactly what our form of participant funding in SeTrans is intended to do.

Finally, in response to Commissioner Brownell, I want to assure her that no one is suggesting that needed transmission improvements to serve customers will not be made. Improvements to maintain the level of reliability that customers have come to expect will continue to be made, and in the SeTrans proposal, those are exactly the types of investments that can be mandated by the RTO and rolled in, again on a subregion or regional basis. Thanks.

MR. HEGERLE: Thank you all. And, Bruce, since you had to wait till last to say something, I think we'll direct the first question to you.

You made the comment that I think people would agree with, that you need comparability in the way investments are treated, and you need to consider generation and transmission expenses as one, really; you have to look at both to meet the customers' needs.

MR. EDELSTON: Right.

MR. HEGERLE: The current system, of course, was built for the current generators to serve the current load at the lowest cost.

MR. EDELSTON: Right.

MR. HEGERLE: Now, if there's a generator, a merchant generator, for instance, that can lower delivered cost, if you build the transmission to it, if you add that together, it would lower the cost. Would you roll those facilities in?

MR. EDELSTON: No, because, again, the customer who is getting that delivered cost needs to be able to choose among alternatives based on the total cost, and the only way that customer sees the total cost is if they face both the generation and transmission costs.

Rolling in the costs requires that somebody else pays a part of those transmission costs and the customers doesn't see the right price.

MR. HEGERLE: But that's assuming one customer benefits. What if multiple customers would benefit; what if an entire rate zone would benefit?

MR. EDELSTON: Well, under the SeTrans proposal, there's nothing to preclude a zone from participant-funding a project or customers getting together to participant-fund a project.

But, again, if it's economic-based, it should be the customers who are funding it and not everybody through a rolled-in price.

MS. FERNANDEZ: Well, I was thinking, having the two of you sitting next to each other, it seemed like there was an opportunity for sort of some cross-discussion.

MR. EDELSTON: I think that wasn't an accident that you put us together.

MS. FERNANDEZ: It's alphabetical.

MR. EDELSTON: You just found somebody named Gross, right?

MS. FERNANDEZ: Mr. Gross talked about -- a lot of the focus of his concern seemed to be when resources -- when he wanted to change resources, and it sounds like sometimes using existing resources within the region and being faced with additional costs.

I guess I'd like to ask, maybe you, to respond to his concern as to why that either should or should not be participant-funded, and then I'll give him a chance to respond to that.

MR. EDELSTON: Well, I think it should be participant-funded, for exactly the same reasons that I mentioned. In choosing what alternatives these Texas coops make, they need to take into account, generation and transmission costs, and if there are increased transmission costs as a result of the decision they make, they shouldn't -- those costs shouldn't be foisted on other customers within the region, because they solely benefit East Texas Coop's customers.

That's point number one. Point number two is, I want to point out that if Southern Company, under our proposal, designates alternative resources in the same way that these Texas coops might, and if that requires additional transmission to be built, we would be required to participant-fund it in the same way that we would expect East Texas coops to participant-fund those projects.

MR. GROSS: Can I respond? I think the key to Bruce's comments is his use of the word, solely. And I would defy anybody these days to be able to solely identify, particularly from the load-serving side, the exclusive benefits of a transmission upgrade.

These transmission upgrades have both economic as well as reliability significance in most cases -- all that I'm familiar with. They benefit all sorts of entities out there that are relying on the grid for economical and reliable power.

And the current situation, what we're concerned about, is that entities like these Texas cooperatives, are going to be -- are being put on the margin, because of their circumstances, where through these transmission impact studies in systems that are right now deficient as far as their transfer capability, that these small transmission requests are and will initiate large transmission dollar investments, which we can't certainly afford.

Trying to shift the burden to the load-serving entities to go out and put together some sort of larger group that could afford to do this, I don't see the processes in place to do that.

The only other alternative that I see is to roll these costs in, given the fact that most of these investments have multiple beneficiaries. So, that's our point of view.

MS. FERNANDEZ: Would anyone else like to comment?

MR. EDELSTON: Could I respond to that?

MS. FERNANDEZ: Okay, I'll give you the chance and then we'll go down the line.

MR. EDELSTON: Under -- you know, in this new world we're living in, it is the RTO who is going to be deciding what upgrades are needed for reliability, which we think is appropriate.

If it turns out that there is a project that these Texas coops suggest for, you know, importing power for their own needs, that also replaces a project that the RTO would otherwise have needed to do for reliability, in that case I think it is perfectly appropriate that there be some benefits going back to East Texas coops.

But if it is a project that would otherwise not have been needed or not have been made to meet NERC reliability criteria, I don't see any reason to load those costs onto customers who don't need that additional reliability and haven't asked for that additional reliability.

MR. ROTGER: I just wanted to point out, at the risk of stating the obvious, that roll-in, or even the slight whiff of roll-in effectively kills all voluntary participant funding.

We have certainly seen it firsthand in our business. The slightest hint that an economic upgrade has a chance of being rolled in and spread amongst something other than the beneficiaries, really means that there is no incentive for that person to sign up.

We have transmission solutions ready for volunteers, ready for voluntary participant funding, but those volunteers will not sign up if there is a chance that they may get their investment -- you know, that their needed investment may be rolled in and they don't have to pay the full freight.

MR. WILLIAMS: We run into the dilemma when developing major base-load projects, and you go out and you say that five years from now, a customer would like to access your project. And the dilemma they have is that there is no bottlenecks that not only you have to solve for your generation, but effectively you solve for about double or triple what's needed for your generation.

And there is no way that a single project can bear the cost or a customer on the other end can bear the cost of that, and yet the customers on the -- the regional customers on the other end benefit.

That's the limit. It's how -- there's now way to unravel the rights there. There's no way to allocate those rights and say, well, you get all the benefit you created, because you reduce the prices for everybody on the other side, not just for 50-megawatt customers here and there.

And the timing to go through this process is, you have to go out and gather, customer-by-customer, and try to follow that, and that's a real problem.

MR. McKINNON: Again, in New England, with our tiered approach, we'll have some utilities that over 50 percent of their transmission assets are paid for locally, and other utilities, more than 70 percent, are paid for regionally.

And you may have a rural transmission owner in Northern Maine versus a transmission owner in a congested state or a densely populated state like Connecticut, and so you do get that.

And if we come back to the earlier question from the first panel about what happens if you winterize transmission in a remote part of a large region. Again, if it was part of the beneficial test to say perhaps it was a 500-KV backbone system and you winterize that, that cost would appropriately be shared across the region that benefits from that backbone, whereas if you perhaps were doing winterization on a 69-KV or 115, that may go into a different tier and not be shared across a large geographic footprint.

So I think the issue is getting simple rules that are well understood, that are both voltage-based and function-based. In New England, we have 345 KV transmission that is paid for locally because it does not meet the functional test of being looped.

We do have radial 345 that is borne by the local utility in a quote/unquote "license plate." So I think a simple test of voltage and functional design; put on a tiered basis, appropriate to the geography and footprint of an RTO, could avoid many of the delays and litigation that's imminent in a more complex structure.

MR. HEGERLE: John?

MR. HOWE: It seems to me that the difficulty in assessing the value of participant-funded upgrades gets geometrically more difficult over time as you get more upgrades being made and sort of interaction among the upgrades, and it becomes difficult to assess the incremental value of each subsequent upgrade, because every element that's added and incorporated into the grid has an interactive effect on the value of every other asset that's been added.

I guess it is for that reason that I'd like to go back and reinforce a point I made earlier; that perhaps if there was a mechanism for participant-funding up front of upgrades, and then some kind of objective test for rolling these facilities in in the future.

I think a lot of people are concerned -- and this is the other point I wanted to address -- a lot of people are concerned that when you add a transmission element to the system, you somehow destroy its value because you eliminate the congestion that gave rise to the reason for doing that in the first place.

You don't destroy the value. What you do is, you spread the value across a wide base of users. The key is to figure out a way to capture and harness that value as sort of the hydraulic pressure to drive the investment in the first place.

If you can do that through a participant funding, through the mechanism of congestion revenue rights -- and there may need to be some other piece to it -- but if you can capture that value, I think that becomes a significant market-based force to pay for these upgrades, but I would grant -- and this I puzzled over a lot in recent months, reviewing the NOPR -- that, you know, you get five, ten, 15 years out, it does start to look very confusing, how do you assess the value of each individual line in the system?

This is why I think that at some point, a roll-in may be more appropriate.

MR. HEGERLE: Jose, you know, what's your response to his proposal, John's proposal about the idea of participant funding up front, and then the possibility of, if it meets a certain test, rolling in later? Does that also kill the merchant lines, the opportunity, or not; does that work?

MR. ROTGER: I think it's problematic. I mean, I'm not sure that it will actually result in what John might think it will. I mean, I think that most people are looking for the free ride, and it's going to be difficult for somebody to pony up, up front.

I suppose that -- I guess I -- let me think about it some more. I don't really have -- I probably haven't thought about it as clearly as I should have.

But at some point I do agree with one thing that John said, which is that at some point, things become more integrated, and there should be an opportunity for rolling in these things as time moves on.

So, I generally agree with that concept. I'm just still concerned that if we are going to have a system, a framework that relies on voluntary participant funding, I'm afraid we're really killing that through all of this other discussion.

That's one of the reasons why I wanted to talk about ITP plant projects, and how do we inject competition into that process? And I realize that's perhaps not entirely germane for today, but --

MR. HEGERLE: Let's tie it together. Kevin?

MR. KELLY: I have a question, and I'll direct it at Bob Gross and Bruce Edelston, but welcome comments from others.

There's a problem that's been described to me with participant funding, which I'll call political with a small P. And I want to describe the problem and get your comments on it.

Imagine a peninsula that's in a load pocket. It's a very expensive generation area, and there are two cities on the peninsula, one of which is a municipal utility, and the other of which isn't and is served by a large utility that serves a broad area, of which the load pocket is just a small part, if you see the picture.

With participant funding, the municipal utility worries that it will have to pay a lot for upgrades.

The citizens of the other city that's part of the service territory doesn't face the same problem, it's said, because the utility, yes, will pay through participant funding to increase transmission for its customers into the load pocket, but under state law, will take that extra transmission cost and roll it in across all the customers to get a flat power rate for all the customers in the region.

And the charge of the municipal utility -- or it could just as well be a coop in the example -- is, number one, they allege that the result is discriminatory, in fact; and, number two, they allege it's a plot by the utility to observe the municipality, who won't sustain that high cost, and will say, we want roll-in rates, too, so have the utility take us over.

That's the problem, which I think strikes me as a real small-P political problem, at a minimum, with participant funding, and I would welcome anybody's comments on that.

MR. EDELSTON: Let me start. First of all, I think one of the problems that we continually have here in these panels and just outside the room also, is that we constantly slip between the physical world of today and the financial rights world of tomorrow.

Under the financial rights world of tomorrow, if somebody in the load pocket peninsula you talk about pays for transmission upgrade, he's not necessarily getting the physical rights to import power. He's getting the congestion revenue rights that are created by that expansion.

He can keep those rights to use to import power on his own, without paying congestion costs. He could sell those to the municipal, but the municipal still gets to import power from where it wants to. It just isn't on hedge in the same way.

If the municipal wants to import the power without paying congestion costs, it has the ability, either to co-fund the project with the larger utility or make some other improvements that get them the congestion revenue rights they need to hedge their bet. So that's the first answer.

The second answer is, I would agree that if one party can roll it in to a larger base and the other party can only roll it into their own customers, that's a problem, but that's not what SeTrans has been suggesting for participant funding. You know, our proposal is that, again, whoever funds the project gets the congestion revenue rights, and they have to pay for it.

And to the extent they are giving those congestion revenue rights for use by their own customers, then they would roll it into the rates of their own customers, but they wouldn't have the ability to roll it into somebody's else's rates.

MR. GROSS: One of the problems that we see is the value of the congestion revenue rights. I understand you may want to get into that discussion at some other time.

But from a small load-serving wholesale entity, from our standpoint, it's very hard to value those and factor that into the equation. I think the situation you described where a wholesale customer and a large integrated utility are faced with a sizeable investment to relieve a load pocket, can be a real hardship, even death knell, on the wholesale customer, be it a municipal or a cooperative, since they both go into the thing paying the same access charge to the transmission system.

And that access charge probably contains costs that have relieved load pockets elsewhere on that investor-owned utility's system and the municipality or cooperative has participated in that, and has paid its share. To all of a sudden switch to participant funding, and ask and go to an incremental approach, without some sort of phase-in or some sort of more rigorous comparability requirement, I think could be a real problem, and under the more diabolical definitions of participant funding that I have seen, that's the way the costs would be allocated in order to relieve a load pocket situation.

These Texas cooperatives are sitting in a load pocket. It's called LOTAB, and that pocket down there has transmission limitations into it. The transfer capability into that area is less than the load in the area, therefore, there's generation in that area that must run.

And when we all of a sudden discombobulate the generation from the transmission, since this started out as an integrated system, and go to the type of things that Bruce is talking about, there's got to be some kind of phase-in in order to get there, we think.

MR. HEGERLE: Bruce, why is it so expensive to build what Bob needs? I guess I don't understand what -- it just sounds like it's very expensive. I don't know the numbers on that.

MR. EDELSTON: I can't answer that, because they're not our customers. I mean, Entergy might be able to answer that better.

MR. GROSS: it's expensive because it back up to ERCOT. You've got the Gulf of Mexico on one side, and it's very difficult to get transmission into that area from where

Entergy's generation is, which is primarily over in Louisiana.

MR. EDELSTON: I would ask the question of whether or not building transmission is the most cost-effective solution. I mean, could generation not be built in the local area, relieve the congestion that way, and could that not be cheaper?

MR. GROSS: It could very well be, but that's not happening on the scale that we had once hoped.

MR. EDELSTON: And maybe the reason it's not happening is, we don't have locational marginal pricing in place yet.

MR. HEGERLE: As I would expect, John has put his placard up, because I'm wondering the same thing. Why isn't the technology he mentions --

MR. O'NEILL: Could I ask a question on this? You said you back up to ERCOT? Have you talked to Jose? He can get you into ERCOT.

(Laughter.)

MR. HOWE: I happen to be familiar with this area, because this is an area where we have a couple of our systems installed and two more on order, which, for Entergy Gulf States and East Texas, has extended the need for transmission, they believe, in that area, by about a five-year period.

So, this is an example of where, if there is uncertainty about the ability to site transmission -- there was an intense effort to site transmission in the Woodlands area north of Houston, which is in East Texas. And Woodlands, you have a lot of energy executives that work in Houston in the energy industry, and they don't want to go home and look at transmission lines, understandably.

So, what we have done there is, we placed a couple of SMEZ devices at a couple of Entergy's substations and have two more on order for installation, probably within a year or so.

And that is an example of how some of this new just-in-time technology can relieve these planning constraints, broaden options, and that was, in total, under $10 million investment. I don't know what it would cost for the required amount of generation.

MR. HEGERLE: Can you help Bob out now, too?

MR. HOWE: I would be pleased to talk after the conference.

(Laughter.)

MR. McKINNON: Again, I think that as the industry restructures, least-cost planning is going to be gone. I mean, what we have to do is create a robust, competitive market planning process that will provide the incentives for efficient capital investments in place of the traditional least-cost planning model.

Certainly in New England, we have not put in least-cost planning -- I mean, LMP yet. It's scheduled for March, but we have -- going into next summer, we'll have in excess of a 30-percent reserve margin on generation. We've had plenty of generation attracted by providing information as to where the needs of the region are.

And, again, it's our RTEP process; it's the market and the way it works that is replacing a traditional approach to looking at alternatives. It's putting it in the hands of the market. And when the market doesn't respond, then the ISO working the TO is built.

That's a viable way of allocating capital in a capital-intensive industry, so we don't get into a situation of would it be cheaper to put a generator or would it be cheaper to put a transmission line in, and who's going to make that choice?

Well, the market should make that choice.

MR. GRAMLICH: Mr. McKinnon, does that mean you're advocating that there would be some -- to get back to this question here -- there would be some economic investments covered by the rolled-in process through the RTO? I think we're going to hear from NERTO later, which will propose a plan that does include that. It's been kind of a source of some debate this morning.

MR. McKINNON: I would say that if all the needs of the region were made available to all competitors, and some projects did not get addressed by the market, and the ISO felt that the timeframe was getting o the point where reliability issues were going to become apparent -- because all projects have both reliability and economic aspects of them -- and the ISO has directed the transmission companies to build, they would build it and they would roll it in, using a beneficial test of voltage and function, and I don't know if that's a yes or a no, but I would think that economic projects would be solved in the marketplace.

MS. FERNANDEZ: Let me ask it sort of a slightly different way: What ability should load-serving entities within a region have to switch resources -- I mean, probably under long-term contracts -- without incurring or having to participant-fund upgrades? If some changes were necessary, those would be part of the plan.

Should they be part of the plan, or not?

MR. McKINNON: In New England, the loads pay the transmission; the generators don't. I mean, when a new generator, connecting under minimal interconnection standard, pays the but-for costs, but beyond that, transmission is paid for through by the loads.

So today, I think about 80 percent of the market is bilateral in nature, and to the degree a load-serving entity wants to do different bilateral contracts, the load is going to pay the transmission.

MS. FERNANDEZ: But would that be part of the sort of the zonal rates or license-plate rate or regional rates? I know there are some in New England.l

MR. McKINNON: Well, New England has -- is moving -- it's a complicated tariff in the sense that it's going through -- I think it's a nine-year transition period to average rate for pooled transmission facilities, which are ones that benefit the region by being the higher voltages and looped.

And so those that aren't, those that are radial in nature, what we're calling LNS, which are, I think what you're saying when you say license-plate. Again, license-plate rates and regional -- utility-specific rates and region-specific rates are both paid for by loads, not by generators.

MR. HEGERLE: Bruce?

MR. EDELSTON: Under SMD in the new world, any customer or load-serving entity is going to be paying an access charge and a congestion cost, and he's going to be hedged for a certain set of transactions and have a set of CRRs to begin with. If they change resources and they're not hedged for that new set of transactions, then they're going to have to pay the congestion costs associated with that transaction.

Now it may turn out that the congestion costs are so large that it's cheaper for that customer to pay for a transmission upgrade to hedge the congestion in that way. That's when those transmission investments will be made. But unless we have that test in place, we don't know whether or not it's economic for that customer to pay for that upgrade.

So, again, I think that's one of the beauties of this nexus between participant funding and locational marginal pricing is it provides an economic test to the customer as to whether or not it's cheaper to pay congestion costs or cheaper to participant fund a project.

MR. HEGERLE: Jacob, do you have a response?

MR. WILLIAMS: One of the dilemmas as far as customer pays is that, you know, let's assume we're not in a retail market. Who represents the customer for those standing behind the utility making those decisions? It gets very murky. And who is charged with providing affordable electricity? And those lines are not nearly as clean as we'd like anymore.

And so the regional planning process is not some centralized way, but it's a way of saying let's look at this and make sure that we're trying to get to affordable electricity that's reliably delivered. It does not mandate everything, but it gives you a template for what should be done. And I think in the SMD, that's where the RTO process and doing a long-term planning.

LMP, as was stated earlier, points out short-term problems and it may be multi-year. The problem is, there's no way to guarantee that that problem today is going to be there five years from now without doing long-term planning to actually see, is that going to be a repetitive situation? You cannot walk away from the long-term planning of the grid to access both generation and transmission take ten years to build. You have to be solving problems ten years from now, not solving today's problems that are frankly going to get resolved anyway.

MR. HEGERLE: In the debate we're having right now, is it fair to say that the question kind of becomes when do you stop waiting for the market to respond and when do you actually build it? The ITP says, as Jose is sort of saying, the ITP plan. When do you go after it?

MR. EDELSTON: If the market doesn't respond, maybe the answer is it's simply not economic for someone to build that addition. And I think Mike Schnitzer said it. We're getting away from the whole notion of centralized planning in a vertically integrated utility that's making decisions as to where to put generation and transmission.

If we're going to have this new market-based system with LMP, I think it really ought to be the market that's deciding what transmission gets built, unless it's needed for reliability.

MR. HEGERLE: Right. But doesn't some of that, whether or not it's affordable, sort of depend on -- it seems to me that the transmission system has been constructed for one purpose over time. We're now moving into a more competitive world where perhaps the needs of the system are different, and maybe we need a different approach to that as far as what should be in or not. Jacob?

MR. WILLIAMS: Look at regional planning. You plan roads and that, you plan 20 years out. You have to have some template, some idea of what's going to happen, and that's what the planning process -- it's not centralized planning, but at least have a vision of what may happen, and then start building infrastructure, some of the major arteries to deal with that problem.

You can't wait for everybody to show up and then say now you pay for it. It just doesn't work. We didn't build the highway system that way and we can't build the major backbone of the transmission system that way.

Certainly there are niche projects that can indeed be done for participant funding, but some of the major planning that needs to be done is well beyond LMP kinds of things. It's great for identifying bottlenecks, but it doesn't tell you what's going to happen ten years from now.

MR. EDELSTON: I would also say that there's not a market in roads, and if we want to build a backbone of transmission and have a national highway system for transmission, then let's forget the whole idea of locational marginal pricing because you don't need it anymore. You now have a system where prices are the same everywhere. It's all been essentially put into taxes like the highway system has, so everybody's paying a small piece of it and they get to use the highway system.

But why have a market-based system of pricing if you're going to do that?

MR. HOWE: I just want to urge us not to give up on market signals before they've even been tried. It's not that markets have failed, it's that markets have not been tried. Once we get the locational marginal pricing in place, it will be a strong indication of where upgrades are needed.

I just wanted to anecdotally mention, we've had some discussion of New England. You may recall a couple of years ago there was congestion in New England. It was estimated to cost about $80 million in the course of one month, August of 2000, a problem that we believe could have been solved for a one-time capital investment of $20 million, that problem could have been avoided.

The problem was there was no incentive at that time for the host utility to make that investment, because it was dollars out of its pocket in order to allow low cost power to flow to other customers.

When we get LMP in place, I think we're going to start to see the market signals align, and there will be a positive business incentive for people to tackle some of these issues.

MR. HEGERLE: I don't know what your response is, but I think we've touched on a little bit, at least some have, the idea that you may need some leveling of the playing field before you go to the market signals. I see one head nod at least. Where do you stand on that?

MR. HOWE: I just want to see us get moving. Since we don't have these market signals in. I think where we have the signals in place, for example, Laura spoke about

PJM in the last panel, and we have begun to see some significant transmission investment as well as more intelligent generator siting practices there. And I think as that model spreads, we're going to see people make some adjustments.

Yes, it's going to be painful. I think accommodating to a world where there are locational differences in prices is going to bring some political cost. But the reality is, we live in a world where, for example, you pay more for a house five miles outside of New York City than if you're 200 miles outside of New York City. You pay more for a restaurant meal in New York than if you are a couple of hundred miles away.

The fact that it will cost more for power in congested areas does flow naturally from the realities of electricity. And there are ratemaking mechanisms to modulate those changes, but I think we should take them as inevitable and as signals for the kind of constructive actions and investments, demand response programs, distributed generation and transmission upgrades that are going to be needed to rectify the situation.

MR. HEGERLE: Kevin?

MR. O'NEILL: Can I ask Jacob a question? You said, and I agree with you, that the LMP price signals are not by themselves enough to figure out what transmission should be built where. What's the alternative? Is there a better alternative?

MR. WILLIAMS: Well, it certainly flags the problem. And we're advocates of an LMP system to flag problems where they're at, because lacking price signals, we don't even know where the problems are, other than people getting shut off or things like that.

But a reasonable planning process that says if these lines get in, customer benefits, prices go down dramatically and it far offsets, that kind of process should supplement, you know, the LMP, so that you see both in the spot market and long-term, this looks like a very good project that customers have true benefit for over a large region.

I think you need both. You can't rely on just spot price signals to solve your long-term planning. It will not resolve. And I came out of a transmission planning and generation planning background.

MR. O'NEILL: Suppose I'm a customer in a load pocket and I have contracts with generators that go out 10, 20 years. And we do the studies, and we show that if the studies, if we upgrade the transmission, prices go down. But I got contracts for the next 10 or 20 years, I don't benefit. I don't want to pay for the transmission upgrade. What do I do?

MR. WILLIAMS: Well, the issue probably is it's not just you, the five or three customers, it's probably the entire region benefits, and the benefits of the entire region should probably trump what a couple of customers have signed in terms of their --

MR. O'NEILL: It's tough luck that I signed a long-term contract with a generation and can't take advantage of the remote --

MR. WILLIAMS: Well, you may have the ability to dispatch back the units and actually access in the spot market the cheaper stuff and only turn on the units you've paid for when they're the incremental resource.

I mean, if you've signed up for must-take, must-run, then you have created a bit of a dilemma.

MR. O'NEILL: Do you sign those kind of contracts?

MR. WILLIAMS: Must-take, must-run? We signed defined amounts, yes.

MS. FERNANDEZ: I was wondering if, I mean, it seems like sometimes when we're talking about the existing system and the problems with it, there are sort of two problems that can come up.

One is that, and I think probably East Texas Cooperative is in this situation, where you have customers of other utilities that feel that they're in a load pocket, so they're faced into, put into more of a market environment, that you don't have the basic transmission infrastructure. You're concerned you're not going to be fully protected in the transition to it.

The other seems like it's more of a concern that the existing transmission system, there isn't much possibility for interregional trade. And so it may be something where, I mean, New York City had maybe more expensive, but it was basically generation built in New York City for New York City customers. Would there be a basis for treating those types of transmission differences differently?

I mean, it seems like the first one where you're a customer of a larger area and you're part of a load pocket, is it something where you can either assure the customer through the transition process with the CRRs that they're going to be fully protected, or that perhaps transmission upgrades are necessary? Whereas it seems like the latter one is more one where you've kind of start out protecting yourself, or your own service territory, your native load, but now it's more of an issue of taking advantages of other opportunities in the market.

MR. GROSS: I can give that a try. As far as our perception of the problem, it has emanated from the situation, your latter description. That is, where a lot of power is going to be exported out of a region into another RTO region, where there are a lot of upgrades necessary to get that power out, it's not fair to burden the ratepayers in the originating region.

That's where the impetus of all this came from, it seems to us, and it has then kind of slopped over into benefits testing within a region as to individual decisions that go on in that region. And I think our feeling is that we've got to make sure that we level the playing field within the region before you go and start trying to assign specific investments to beneficiaries, assuming that you can identify them.

The system that's in place now is a fully integrated system. It takes into account the existing generation and the transmission. And to go from that type of system over to one that where you start measuring incremental benefits, there's got to be some sort of phase-in process. Otherwise, small wholesale customers who are going to be on the margin are going to be put at a tremendous disadvantage.

MR. HEGERLE: We are justa bout out of time. Kevin's got a question he'd like to ask.

MR. KELLY: For Mr. McKinnon. I've had a concern that with certain types of participant funding we might build capillaries but not arteries. And your presentation talked about, at least as I understood it, that there was some local planning, regional planning, and super regional planning with costs assigned appropriately.

And I wanted to understand that a little more about -- you're in a market environment now in the Northeast, how that kind of planning at three levels fit with reliance on market forces.

MR. McKINNON: Because we're in our second RTAP plan conducted by ISO New England, are the needs are put out. Again, RTAP-2 is in its review stage now. I think it's set to be published in December or January. But it would identify four needs, at least from a transmission perspective, one in New England. And the four projects were Southwest Connecticut, Maine to Boston, Rhode Island to Boston and Rhode Island to Eastern Connecticut.

So the four big transmission needs were identified. Ranges of congestion potentially created or solved by those were put out to the public, and then generators, merchant transmission, DSM providers, I mean they had an understanding of where the problems were, what the loads, what the anticipated generation that was already in queues was, and what the potential impacts economically on the power market was.

And so the regulated transmission companies have transmission solutions to that. They're not being implemented currently. We're trying to move forward -- my particular company is trying to move forward with solutions in Southwest Connecticut. We're having lots of siting problems, but certainly the ISO is participating in the siting discussions and is sharing its expertise with local agencies to assist in the understanding of need.

So I hope that's responsive to the question, that the information was shared with all participants, and participants are free to -- if someone wants to build a large generator in the right location and change any of the needs identified in the RTAP, they're free to do that.

And indeed, the discussions we're having as we are trying to move forward with a joint filing with ISO New England/ISO New York hopefully in the near future, we talked about the fact that if at some point a project started on a cost basis under the direction of the ISO, then a market solution came in. So if a transmission plan had a five-year horizon and a generation plant got built two years into that project and changed the need for it to exist, then the transmission owners would indeed stop building the project at the direction of the ISO. We would simply like to recover costs prudently incurred to that point.

MR. KELLY: So if I could just say it back to you as a test of my understanding, there's planning done at the local, regional and interregional level, and there are plan or plans developed. And they're published so that market entrants can come in and substitute for them. And in theory, the market could satisfy all the needs.

But then what I'm missing is, to the extent the market doesn't, do the plans go forward and the costs are then assigned at the appropriate local, regional or super regional level?

MR. McKINNON: Super regional is really not happening yet in the sense super regional in my mind means New York and New England, and that's a concept that's being developed and is not operational per se. But, yes, if a project was, by the rules of the pool, if a project came in and it was clear that it was nota regional asset providing regional benefit but rather was a radial line serving a local area, that discussion of how the assets should be classified would occur in established committees that have full stakeholder participation. In New England it's called 15/5.

But the rules are clear. It isn't like every project is a full open debate discussion. It's a hear the rules, is this 69 kV or above? Is it radial or is it looped? And that's basically clear guidance as to that discussion.

But, yes. So each project would have to go through the committee structure and be agreed upon as to what classification it was. And once its classification was established, its rate treatment is very clear.

MR. HEGERLE: Jose has a comment, and then we'll have one more question, and then we'll wrap up this panel.

MR. ROTGER: Thank you. I'm not quite sure where to start. With respect to the so-called "level playing field", I mean, first of all, we have strayed very much into transmission planning. I just want to make sure everybody understands that. And so on that basis, I will proceed.

Transmission planning is tremendously important here, because, as I've already suggested, there is a real tension between a market-based project and a regulated project. And a lot of what I'm hearing today in terms of a level playing field basically ensures that there will not be any market-based projects. Because there will not be -- when do you decide that the playing field is sufficiently level? When do you decide, as you've already pointed out -- the hardest thing in the planning process is deciding what is the test for market failure? And we have some ideas that I won't get into.

But this is critical, because -- Bill talks about the example in New England. New England had one price for all of New England. And I've got a project between Maine and Massachusetts sitting on my books. But there's no incentive for anybody to sign up for that.

Therefore, the planning process is viewed as the way things get built. We want to build transmission. We want to build transmission on a market basis. We want to build transmission on a regulated basis. We're waiting for the rules to be set.

My parting comment is that your commission gets to decide how much of either one of these transmission investments I pursue. And the activist planning process that is being talked about here effectively ensures that I need to pay very close attention to this transition planning process to ensure that there is a competitive portion to it, that new entrants have a fair opportunity to participate in that process, and that that process doesn't undermine or undercut any existing merchant or market-based projects that I have risked my money in.

And that's fine. I don't necessarily have a theoretical problem with that. But I guess the hard task the Commission has in front of it is deciding which one of these models is the future.

We're willing, speaking for TransEnergie U.S., and I think John might agree, we have the technology. There's been some things said here today that I disagree with. There's been a wholesale disregard of the impact of technology on this business that we can talk about further.

But there is investment there. There are companies willing, ready and able to invest. We just need the rules straightened out.

MR. HEGERLE: Thank you. Okay. I think that will be it for this afternoon. I thank you all very much for coming.

To the extent you have reactions to what you've heard today, please submit comments.

We're going to start at one o'clock -- two o'clock. Yeah, you're right. Two o'clock. We're going to go back in time.

(Whereupon, the Technical Conference recessed, to reconvene at 2:15 p.m. the same day.)

AFTERNOON SESSION

(2:15 p.m.)

MR. HEGERLE: Okay. We've had two excellent sessions this morning, and we hope to continue our progress this afternoon with where we started this morning.

I think we managed this morning to focus the debate, just a little bit, on the basic question of what kind of facilities ought to be mandatory and rolled in.

We got past the, you know, everything is participant funded or everything is rolled in, and we're somewhere in the middle now, and we hope to push that a little bit further and get a little closer to what the right answer ought to be, and we've got some excellent folks here to do it for us.

I think what we'll do again -- and we've got a little more Western flavor this time, and Midwestern. If we can just start down the line and I'll give you a couple of minutes to just sort of lay out your basic approach to participant funding and how to finance these facilities, and then we can, the Staff and others can ask questions.

So we'll start right down here.

MR. BAYLESS: I'm Rich Bayless from PacifiCorp. And before we get started, Charlie Rheinhold wanted to make sure I brought -- you can't have a transmission discussion without an unintelligible transmission map. So it's here.

So we're okay.

(Laughter.)

MR. HEGERLE: Just lay it out in the middle here.

MR. BAYLESS: PacifiCorp, we're for new markets. I'm a planning and an engineer, and I've been looking at all the pricing options. And to me, looking at the math, whether a load-serving entity serves via pancakes, rolled in or license plate just is really a question of who and where the costs get recovered, who pays.

We probably more than a lot of folks in the West worry about that a lot because we spread it across all the states, and the West is big. We have 17 states and provinces in three countries not including Texas, if you don't include that as a country.

I heard Minnesota down to Mississippi. Well, we go from D.C. down into Mexico. So we've got a lot of diversity both in jurisdictions, ownership, and the way and how the system is used. So we really want to promote that we require flexibility and variations in whatever rules may result or pricing policies.

We need the flexibility to get voluntary RTOs formed where we can address this so that everybody can participate. Otherwise, what we're going to require is airtight reciprocity from those that choose not to.

So we're spread around the system. We are into the east side of the system where it's sparse but where there's a lot of coal and renewable energy. So we like the idea of fully rolled in. But being pragmatic, we're content to work with license plate and access fee areas as long as they have transfer charges to the other access fee areas where required for the large amount of bilateral contracts and so forth that we've done over the many years to represent the existing system.

For new, we'd like to see it again on a rolled-in basis. But because if we go to LMP and injection withdrawal points, the way the system is, it's very tightly connected, so we're going to need to see multi-state planning and identification of projects that roll in.

And I wasn't quite sure when we started what we were talking about, market-based participation. And I'll talk about that in a minute. But I think along those lines, we're really looking for mandatory participation based on independent transmission providers and multi-state committees working to agree on what should be local versus regional, and in any case, roll it into the local access areas.

Requires the multi-state stakeholder and commission committees to help us do that with backstop authority to allocate costs, and along those lines. And we're going to need to make sure we have jurisdictional clarity for cost recovery so we don't see jurisdictional gaps.

But we do have room for what I'm now understanding, or I thought at one point, the market-based participant funding meant, and that is if a generator comes along and really wants to get on the system but because of where they are on the boundary of one of these areas that we've chosen to set up the market, and it happens to be chosen in the wrong way that they're sort of in the middle or in the average, they can choose to come in and make their investment go get on the system, take their chances in the redispatch market or to get to a hub, and for that they'd receive the CRRs, until some point some LSE, some ITP, some local access area decided that that resource was needed in the mix for network resource and for the reserve requirements.

Anyway, that's our story, and we're sticking to it until the rules change and we change it next hour.

But I did want to talk about Wyoming, Colorado and Montana. We did a governors' study back at the height of the power crisis when the prices were very high and everybody was very concerned, and the study looked at the whole region as one planning basis.

We looked at two scenarios, expand with remote coal and renewables, and put in the transmission that that might require versus build the generation resources we're going to need over the next ten years from close in, gas sort of generation.

The study found out that if you built the transmission to integrate where the cheap fuels and resources were, you could -- the customers, the end use customers all over the region, could spend a dollar per megawatt hour, and they'd save $7 per megawatt hour for the power delivered if you spread the cost of the new transmission over to everybody.

But if you were instead to take the transmission costs and just spread them across the new generation, mostly coal in this case, that added $5 to the long-term marginal costs of the coal units, bringing them up to just at the marginal cost of the spot price from the gas scenario.

So if you took the transmission that benefited everybody and put it on that one segment, they're not going to take the chance, and they're not going to take the chance.

So the other thing we found was that the transmission that was built for that scenario caused a savings to all -- and the new generation we're talking about was 25,000 or thereabouts megawatts out of 160,000-megawatt base. And the new transmission caused about $1.4 billion in congestion savings to all generation.

Now if you take that and put it on just the new generation, take that transmission and put it on the new generation, that's a savings of about $8 per megawatt hour. So if you could somehow figure out how to focus the congestion revenues from the CRRs just to those guys and keep the free riders from benefiting from it as well, it's economic. Otherwise, it looked to us like you need to socialize.

So looking at that, the governors were trying to puzzle through how to pay for things like that to encourage competitive power markets. And we've either got to spread it or we've got a very complex but maybe doable allocation method to try to move it amongst the various areas.

But if we ended up -- what we did find, if we did end up putting it all on the new generation, it probably wouldn't happen. So the governors are waiting to see how these issues stabilize and what the rules are.

That's basically our story.

MR. HEGERLE: Thank you. Beth?

MS. BRADLEY: Yes. I'm Beth Bradley with Mirant. I'm the lone Southerner on this panel, so it should be interesting to see what everybody else wants to say. And since I'm mostly focused on the South, I don't have a great appreciation for the West, although I've been educated in the last two days a little bit about the issues out there.

Basically, I just want to go over what Mirant's positions are on participant funding. And I hate to agree with Bruce Edelston, because after our spinoff is Mirant, we don't usually agree every day. But, Bruce, thank you for this opportunity.

We do believe that new generation expansions and transmission expansions for economic purposes both need to be treated on an equal basis. That LMP must be in place to provide appropriate price signals with a node-to-node model rather than this contract path model or the physical world that we're in right now, for each tie line between adjacent ITPs or RTOs.

Again, what Mark Schnitzer talked about earlier is, we're moving from a physical world into everything's based on a financial world. So when you've got that, you've got to basically be able to match apples with apples and oranges with oranges. Otherwise, you get into these issues that I think we heard earlier today where you're trying to make a black-and-white picture and you need more flexibility, more areas to investigate with new products.

The other thing that we feel is very important is that the ITP must be truly independent of all market participants to ensure that any transmission built for reliability purposes doesn't become a vehicle by which costs are improperly allocated to generators, as is currently done in some of the vertically integrated utilities today.

So, therefore, we believe that transmission projects built for economic purposes or economic reasons such as reducing congestion or increasing export power should be voluntarily participant funded.

On the flip side, transmission projects that are upgrades that are required for reliability or stability purposes, or even considered mandatory by the ITP RTO, for the example that Kevin brought up earlier, the lights are going to go out, should be rolled-in pricing.

One thing about economic investments, though, is basically we have to ensure that if we make these investments that we are assured getting a payback, whether it's through CRRs or some other more flexible option, just like a high return on equity, accelerated depreciation, maybe property tax incentives, something like that. And there might be other things like transmission credits that we need to consider. I know that's one of the issues you had for later, and we'll get to that one.

But we believe that expansions may be built by either a merchant transmission company or transmission owner and funding can come from the participant requesting the expansion.

And finally, we don't believe that the ITP should decide that incremental transmission expansion is economically justified and then have it unilaterally built and then assign it to a participant. We don't want to see those situations occurring.

So, with that.

MR. HEGERLE: Thank you. Scott?

MR. HELYER: Thank you. I'm Scott Helyer with Tenaska. And I'm a Southerner, although my company is based in Omaha. I've grown up and still live in Texas. But I guess I appreciate the opportunity to be here.

Tenaska's view of this, and speaking strictly about participant funding, is that we can support participant funding within reason. There's all kinds of different ways that we can do all of this, and we've been hearing a lot of that debate.

We believe, though, that if we're going to do participant funding, it must be clear that a particular customer is the sole beneficiary before it's assigned the cost.

We've heard some discussion, and I'll repeat a little bit maybe of what was said earlier that it's one thing to sit here today and look at some studies and be able to point to something and say, yes, you're the one that's causing this problem. But five or ten years from now, I'd almost dare any planner to go back and start pulling apart the system or whatever and say, you know, that was the person that caused the problem and continues to cause the problem. You might find that in some cases, but once things are integrated into the system, it becomes an integrated transmission system.

We believe that any assignment of the costs, if you are going to assign them to a particular entity, must be made by an independent entity such as an RTO, and that any investment, if it is assigned, must be fully recovered, and we're not necessarily convinced that CRRs by themselves are going to allow the full recovery of that investment. We think there might have to be some other means in place that would allow the full recovery.

We believe that the customer needs to receive all the property rights associated with that expansion so that other market participants are not allowed to benefit at say our expense or another customer's expense or what have you. As you've heard discussed, anytime you go put in a transmission upgrade to the system, it's an overall improvement. And the transmission wires or the transformers or what have you by themselves can't distinguish between whose megawatts are flowing on their piece of equipment. It's there and everybody is then using it.

There's lots of things that we could talk about. One of the things that I've been thinking through, you know, people keep pointing towards generators as being a cause of or a need to expand the system. You can sit here and think of all kinds of different examples, and one thing I've been trying to think through is what would happen in participant funding world, for example, if a large amount of load in a certain area got a price signal that was so high that it said I don't want to take electricity, you know, for the next few hours? Or, you know, anytime the price gets that high, I want get off the system.

If they were to leave the system, it might create a problem. It might result in a bottleneck out on the system for other customers that are left. Now is the load that's now left the system going to be assigned upgrade costs to go fix the problems that are being created because it no longer wants to be on the system at high prices? It's a little backwards thinking along that line, but if we're sitting here trying to put in place a mechanism that says we want people to respond to prices, it may be that the response is, I don't want to be served at that price, so let me get off. And it could create an issue or what have you.

Sometimes you need to think about things from a different perspective in order to try to understand whether or not the participant funding is something that can completely work as regards assigning it to a particular entity. There may be times where it's very clear, but there's probably going to be mostly the time it's not going to be very clear as to how to deal with this.

MR. HEGERLE: Chuck?

MR. MEYER: I'm Chuck Meyer, Vice President Transmission Marketing and Sales, Bonneville Power Administration. I want to start out just a little bit differently than I've heard some of the other participants that talk about this particular issue.

You'll hear or see Bonneville say that they're interested in promoting competitive markets. But we actually take it a step further in our mind. We look to see what do we think is in the best interest of the consumers, largely within the footprint of the Bonneville system in the Pacific Northwest.

Now there may be a direct correlation between competitive markets and what's best for the customer, but rather than get into that argument or discussion with people in our region, we've chosen to take it to okay, so what is actually going to help our consumers with their energy needs?

To that end, we have concluded that one of the most important things that can happen in the Pacific Northwest right now is we need more generation. So then from a transmission perspective, how is it that we're going to get more generation in the Pacific Northwest?

What we've embarked on is a fairly aggressive, we call it infrastructure program. We're constructing or in the process of constructing $1.4 billion in new transmission. It's broken down over 20 projects. Those projects are for a number of different purposes, and I think this will be right to the point that you guys are looking at today.

A lot of those investments are for what we've been calling reliability today. And in those areas, those reliability projects, we're rolling them in. Now again, we're not talking about RTO West. We're talking about pre-RTO West and what it is Bonneville is doing. So those investments are being made. The intent is to roll those in.

We have some of the other projects that we're doing are really, it's almost the but for test. We're doing those projects exclusively to integrate new generation. An example of that would be what we call the John Day McNeary Project. Seventy-seven miles of 500 kV line intended to integrate two generators for approximately 2,200 megawatts. That project is intended to be funded by those two generators. In return, we will then refund the money as credits as they use that project over time.

We have a third type of investment that we're doing that I haven't heard anybody address but I have heard FERC acknowledge, and that is demand response programs or what we call non-wires alternatives. We have determined in at least a couple of different places that we could substantially delay or defer the need for transmission by getting involved with the stakeholders and the local communities in terms of what is necessary to be done either in moving capacity, you know, out of an hour when it needs to be moved out, or even option say as distributed generation, something like that.

And even though that's in a preliminary stage, it's looking like it's going to at least pan out in one of the projects that we've got going, and we're going to be looking at some others.

Earlier this morning somebody said that least cost planning was something in the past. Well, traditional least cost planning is, but if you're going to put a wire in, there may be other alternatives to the wire. And I think people should be looking at that.

So you guys also know we are an active participant in RTO West. And in RTO West, that model is essentially one of having if a generator wants to hook into that system, they're responsible for paying for the cost of doing so. And we're, you know, putting that forth along with the other participants that are involved in that.

We do think that we have to give some consideration to transition. I think that was one of the questions you guys were even asking, how do you get from where you are today to where you need to be?

That's one of the reasons why we've been as loud and pushing as much as we have the importance of contract rights and making sure that people have the opportunity to, if they want to hold onto their pre-RTO contracts, that they should be allowed to do so. But if they choose the RTO world of, say, not getting their credits for the investment they had made in that transmission and would rather have the CRRs for doing so, you know, and participate fully in RTO West, that should be their choice in doing it.

Just before I conclude, I want to make a few other remarks about the points I just made. So even though we're asking participants to come up with the funds, and we have two major projects, two of the first projects we're doing, the generators essentially have completely evaporated and gone away in the last four months.

And this has, in part, to do with the boom-and-bust cycle that was going on when the prices in the West were as high as they were, you know, just a year and a half or so ago. We had requests for interconnection for 35,000 megawatts.

That list has now collapsed to 20,000 megawatts and the reason why it hasn't collapsed further is that people just don't want to get out of the queue. They're looking at it as the property right of being in the queue. The number might be approaching zero.

There's a crisis going on with access to capital, and all the generators -- you know, when I'm asking them for $77 million to do a transmission line, they can't come up with the money.

We have negotiated agreements. We have, in fact, taken several millions of dollars from some of these people and they paid for the environmental work and taken the project right up to where we're now the -- you know, the EIS is about to be done and we're in a position to sign the contract to move forward, and they're not there any longer.

So we have to be, and you're thinking about and deliberating on what you need to do with SMD, and if you ask participants to pay, that's a substantial amount of money and are they going to be there and be able to pay that in addition to the costs of doing the generation?

The other thing on that is, it has already come up this morning that I wonder about too, is that if you give somebody congestion revenue rights instead of credits, you know, by definition, if you built the transmission, you've taken care of the congestion that was going through there.

The CRRs, I don't believe, are going to be worth as much as actually having rolled it in and giving them the credit afterwards. That may be a disincentive to what we need to do.

And just the last point: We're so concerned about how this may play out, and is why we recommended we recommended an RTO -- that there be such a strong planning function, not just to ask the transmission participants to -- more or less require the transmission participants to go ahead and solve reliability problems with the transmission, but we even have a phrase in there that talks about chronic congestion.

You know, if there is some market failure that's going on there, we want the RTO to be able to, quite frankly, through a stakeholder process involving the community in that, talk about the implications of that chronic congestion, and whether or not the -- even though we're wanting the marketplace to solve it, whether or not we need to come back in and solve the problem. And that would be in the best interest of the consumers of the region. Thanks.

MR. SCHARFENBERG: Bill Scharfenberg. I'm an attorney with Paul Hastings, and I'm here on behalf of the National Rural Electric Cooperative Association.

Just by way of background, we're a not-for-profit national service organization. We have 930 not-for-profit Rural Electric Cooperative members. We serve 35 million customers located in 47 different states.

NRECA's members serve load. Their primary concerns are in supplying economic, reliable power to their member customers, and, therefore, our perspectives on this topic are rooted in our load-serving obligations.

In terms of the Commission's proposed pricing policy, our view is that with regard to interconnection of new generation, if an upgrade is required to accommodate an interconnection request for a generation project intended to serve customers outside of the ITP's footprint, the party requesting the upgrade should be required to pay for the measurable, identifiable costs of network upgrades that would not be required in the absence of its request to interconnect.

Conversely, if a new generator is being constructed inside the ITP footprint and has a long-term commitment to serve load within that footprint, we believe that the associated network upgrade costs should be rolled into the ITP's transmission revenue requirement.

The only footnote to that is that in a situation where you had an extremely large ITP footprint, we believe that there may be a need for transmission pricing subregions.

With regard to network transmission upgrades that are need to accommodate changes in a load-serving entity's resource designations, load growth, including adding new delivery points for existing resources, once again we believe that the costs associated with those network upgrades should be rolled into the ITP's overall transmission revenue requirement.

Our feeling there is that, you know, cooperatives are on the system long-term. They have been paying a long-term investment cost of the system, and it would be appropriate to roll in those costs.

I guess one of our member's fears, so to speak, would be if a rural cooperative requiring to upgrade, or being required to pay for upgrades, was required to bear those costs alone, and for them not to be rolled in over a larger base.

Whatever the appropriate test employed ultimately by the Commission, we think that it's absolutely essential that they be applied consistently. What I mean by that is, whether the generator is being instructed by the cooperative or its merchant generator, we believe that the same rules should apply within that region.

And, finally, I would just like to say that in terms of elimination of rate pancaking, we believe that it's an appropriate role of the Commission to strive to eliminate rate pancaking, but on the other hand, we think that it's appropriate to look to the regions to come up with solutions as to how that should be done. And that concludes my remarks.

MR. STARCK: Good afternoon. My name is Les Starck, and I'm with California Edison, and I appreciate the opportunity to talk today.

From Southern California Edison's perspective, the problem that we're trying to solve here is how are we going to be able to get enough transmission built in this country to accommodate competitive wholesale markets, to make them robust and work very well?

And the debate that we saw this morning focused on basically two ways of going off and getting that done:

One was, we ought to have a market-driven process that tries to achieve this robust transmission grid, and there are others like Nick Winser, for example, who say we ought to be doing something more not on the voluntary basis, but more on a mandatory basis. Something ought to be done through transmission planning.

Southern California Edison disagrees with the notion that the development of new transmission investment in this country ought to be based upon a market-driven planning process where transmission owners like our company are relegated to the builder-of-last-resort status.

We just simply do not agree that transmission owners and ITCs should basically be kind of the residual players in this market, that we should sit back and wait to see where there's a market failure, and then come in and say, well, then we'll satisfy what the market needs.

We think that is just got it opposite, or it's got it reversed in terms of what should be in place. We are concerned that leaving transmission investment on the basis of this voluntary approach will not result in the robust transmission grid that FERC simply wants.

Quite frankly, we do not have much confidence in reliability through markets. We've been there in California; we've tried it, and we had a lot of problems making it happen.

What we believe is necessary is that you need to have transmission planning conducted by regional transmission planning bodies, filled with transmission planners, working with transmission owners, independent transmission companies, other market participants, to identify what goes on or what is needed in the transmission grid.

Such a transmission planning process, a regional transmission planning process, would take into consideration, many things that are going in the market.

I'm not saying that you ignore what's going on in the market. You will have, you know, merchant transmission going on out in the market. They will be pursuing reliability, perhaps, related projects.

They may be pursuing economic projects, but they will be doing so on their own nickel. You will see generation projects being pursued, pursuant to trying to satisfy resource adequacy requirements of load-serving entities. You will see demand response proposals coming out.

You will see distributed generation, but the transmission planner, at the regional body, ought to be cognizant of what's going on in the market, and then decide what specific transmission upgrades are necessary to accommodate all those things, and to ensure reliability in a competitive, wholesale market.

So the distinction is, we're not saying just rely on markets, but we're saying put a transmission planner in effect that takes into consideration, what's going on in the market, but then goes off and defines the specific upgrades that need to be done.

Once the transmission planner decides what needs to be done, we believe transmission owners, independent transmission companies, ought to have the obligation to build those transmission upgrades.

They ought to get on it and make it happen, okay? Now, to the extent that the projects that they engage in are reliability-related, as determined by the ITP, they ought to be rolled in.

To the extent that they are economic-related projects, like congestion relief project, if the congestion relief project is done by the transmission owner, we believe it ought to be rolled in.

But if there is a reliability -- excuse me -- if there is an economic-related project pursued by a third party, a transmission company, for example, then it could be done on a participant-funding kind of a basis.

And merchant transmission projects can also happen, and if a merchant transmission project is being proposed throughout the grid, then it ought to be on a participant-funding kind of a basis.

But our message is clear; we're not comfortable relying on the markets to make sure that we have reliable systems to create wholesale markets that are competitive. We believe there needs to be a robust planning function and transmission owners have a big role in making that happen. Thank you very much.

MS. ZIBELMAN: Thank you. I'm Audrey Zibelman, and I'm with TransLINK. I'm going to taking a little different tac, and the first thing I'd like to do is talk about ice storms in Minnesota and who should pay for the transmission upgrades when we're upgrading the system to address those issues.

I think that also helps me get into where we see these issues lying, and I agree with Les that we have a couple of issues before us: One is, how do we get transmission built? And then secondly, how -- when you get it built, how do you make sure that the right people are paying for it?

And I think, as you would imagine, that our highway zonal pricing concept was designed to allow you to address both of those issues in a way that we think ends up being the fairest way for all participants in the market.

And so going back then to the ice storms in Minnesota, I think the issue, the first question is, what are we doing? If, in fact, we're worried about that 500 KV transmission line that moves power from Manitoba Hydro down through the MAPP region and everybody relies on in order to provide reliable service in the region, is effectively one of the largest contingency outages we're concerned about, I think that everybody in the zonal region ought to pay for those upgrades.

As a matter of fact, without that 500 KV line, the region wouldn't be secure, so in that case, it becomes an easy question, and under our pricing concept, because it's what we call part of our highway facilities, would be paid on a postage-stamp basis by everybody in the region.

I want to make sure that I note that I agree that with a region, an RTO the size of the Midwest ISO, we're probably going to have to have sub-pricing regions.

The idea that people in Ohio should pay for that, or New Mexico, may be a little far reaching, but certainly the people in the MAPP region who really do rely on that system, should probably have to pay for part of that upgrade.

Now, let's say that, instead of that, we're really worried about these towers that are falling down in Minneapolis on the 69 KV line, and we have to reinforce that because of the ice storm. Who should pay for that?

Again, under our pricing scheme, we're saying that should be rolled in, but it should be rolled in to the local pricing zone. And the people who are benefitting from that are really the customers of NSP, one of my old companies, who are in that pricing zone and use that system in order to move power from the highway grid back to load, or the generators who are in that region.

gion.

And so under our pricing scheme, that would be divided, half between the generators and half in front of the transmission.

The next question I want to ask is, what do you do when you're trying to export? And we do have that problem, and I know we used the south-to-north, and I'd like to think of another region.

We have a lot of capability in the upper Plains States, particularly in the Dakotas for wind resources. There's a huge desire to see renewables developed in the Midwest. The problem is, as everyone knows, if you watch the elections last night, there aren't a lot of people who live in the Dakotas.

(Laughter.)

MS. ZIBELMAN: So if we're going to build that generation, it needs to go somewhere. And what we need to do is just think about, and who's going to build that -- who's going to pay for that 345 line.

Now, if we say, for example -- and we, in fact, are building a 345 line in southwestern Minnesota today for wind outlet -- the issue is, should the wind generators pay for it, or should somebody else?

In my view, and what I know is that when we looked at building that 345 line, we didn't just say that the reason we were building it was for the wind. That's true, but the beneficiaries went well beyond the wind generators.

We also knew that we were curing loop flow problems in Iowa, we were curing loop flow problems elsewhere in the Dakotas, and so to say that the wind generators should pay for that because it's just built for them, to me, is sort of a -- of the fact that that's not how the system works.

It is integrated, and when you do something, you may be avoiding doing something else. So, again, in our pricing scheme, because the beneficiaries of that tend to be everybody who uses those regional highway facilities, we think that, therefore, needs to go into the highway zone.

That being said, it's clear that from my perspective, this should not be the primary mechanism to getting new transmission built. It really ought to be a default mechanism, if all else fails.

And the way I look at it is this: Like Les, I think that we need to go back to the roots of planning. And the way that we're going to do planning is very much we'll get input from the new generators. We'll get input from the LDCs or the load-serving entities, from the transmission-dependent utilities and look at what we see as regional reliability issues, and TransLINK develops a plan considering all of those alternatives.

If, in fact, some generators want to come in and they want to be able to export, we know that if we're going to try to roll that in, we're going to have to defend it by demonstrating that there is a benefit there that goes far -- goes beyond the generators.

And I think, as an ITC, you could be assured that we're going to make sure, because we're the ones who have to defend it on a local siting process, that it's needed, as well as at an RTO vetting process, that we're going to want to know or be able to demonstrate it to our own minds, that there is a benefit beyond the generators.

So what I would like to see is that what happens is, you have a planning process; the planning process develops what's necessary for the transmission for the region in terms of both load-serving and generation outlet, and also for how it affects congestion.

And if the ITC or a TO comes forward and says I want to build this and here are the benefits, that becomes then part of a rolled-in pricing, and we would say it would be rolled in, either on the highway-type facility where it's regional, or in a zonal price.

If, however, as an ITC, I look at that and I say I can't defend it a serving any other purpose but befitting you, and so I'll do it, but I would want to do it on a participant-funding basis or I'll do it on a merchant basis, but I'm not going to want to demonstrate need, or you can have someone else do it, then it becomes up to the generator who then would go ahead and build it.

I think that we have it a bit backwards. I think we should start with the planning. We should start with the assumption that we're building something that's for a public good, and when the person who is going to be on the hook to try to get recovery can't defend it as providing a public good, then we can default to a participant-funding vehicle. Thank you, and I look forward to your questions.

MR. KELLY: This panel seemed to me to have a lot of agreement, despite the geographic diversity and stakeholder group diversity with, I think, the exception of Beth Bradley, to say that where the first panel, some proponents -- there were some proponents of saying rolled in is -- should be used in what I'll characterize as a very narrow set of circumstances, which, you know, if the lights would go out, do rolled in, otherwise do participant funding.

Again, Beth aside for the moment, I think -- I want to test whether this panel is in agreement that the -- on almost the opposite, that is, there is a presumption of rolled in for most transmission, based on planning, with room for participant funding where a particular project is clearly the sole beneficiary.

But the real question is, do you agree with one another? Feel free to just converse without me recognizing you, to see if you agree.

MR. BAYLESS: I think that's exactly where we are, and I didn't realize that I agreed with TransLINK so much. But we were a little confused with the TransLINK proposal about how the original access areas accounted for transactions, contractually, on the existing system and other access areas, but as far as the regional sort of component, the high-voltage or highway component, we agree that that's a good way to do it, as long as you take that in as a component and it gets added to the local area access fee, so it's not a pancake. But that's exactly where we are.

MR. KELLY: I'd say, just jump in. Do open mike for a few minutes, just to see if you really do agree, in the main, on this subject.

MR. SCHARFENBERG: I would agree with your characterization of the basic consensus. Once again, our view is that, I guess the presumption should be rolled in, as long as it's serving load within the footprint, and that should be the starting point, and if you're serving load outside, then consider other things, but the presumption should be rolled in, inside.

MR. MEYER: So with that comment being made, then feel obligated to say something, because even though a substantial amount of the investment program we have going on, we want to roll in, we do also feel that when you're going to make a substantial investment and it is to benefit one or two customers, that rolling it in wouldn't be the proper way to go.

And I guess to also respond to a remark that I heard this morning -- I forget who it was that said it, but they said something about that you might make it a transmission investment for a generator who wants to export this year, but next year, they might decide they want to use the network, rather than exporting.

Another very important reason for getting participant funding up front is that if you build a substantial piece of transmission, say, in our case, John J. McNair for $77 million, and they change their mind or they go bankrupt or something else happens to them, then what do you do?

And so part of our philosophy here -- and I'm going after the participant funding on these -- but for projects was largely also then to mitigate our risk that they do change their mind or they do go somewhere.

MS. FERNANDEZ: Can I ask a followup question?

MR. MEYER: Sure.

MS. FERNANDEZ: I'm not certain if you're saying different things or not. Mr. Scharfenberg said it from the perspective of load within the region.

When you were talking about customers, were you talking about customers as load within the region, or customers as generators?

MR. MEYER: Largely generators.

MS. FERNANDEZ: Would your answer be different if you were talking about it as load within the region?

MR. MEYER: Probably not.

MS. FERNANDEZ: Okay.

MR. MEYER: I would probably agree, I should say. I would probably agree that it should be rolled in.

MS. FERNANDEZ: Okay.

MR. MEYER: Yes.

MR. HEGERLE: Moving right along here --

MS. FERNANDEZ: I was thinking that Audrey was sort of at the end, and when we kind of got to it at the end of the first panel, but we had done sort of the sheet in terms of what type of investment should be included in the plan, and a lot of that gets back into sort of the what should be mandatory.

I'm also sensing that for most of this panel, the answer is it's much more beyond reliability. It's looking at a lot of sort of economic factors, at least in terms of curing chronic congestion. And are there other things that should be put in?

MR. BAYLESS: Chronic congestion has couple different interpretations, even in RTO West, but I'd like to see, or at least our position is that we'd broaden it to be, if it's economic for the region, and not just necessarily a chronic area that always has congestion, that somebody should fix or cost should be allocated that somebody fixes it, but, for whatever reason, it hasn't happened.

Sometimes those are market issues that market mitigation should fix, whatever the reason. We see it broader that than.

If there is an economic reason that the multistate planning group can perceive, and in the studies that are done between the local area access and the multiarea or inter-RTO study group, the benefits can actually be allocated various ways.

We think it ought to be done and include that. Chuck?

MR. HEGERLE: It's Audrey we're trying to get to, actually.

MS. ZIBELMAN: I'm not quite sure. I want to just make sure I understood your question. You were asking what, besides reliability?

MS. FERNANDEZ: Well, it seemed like when we first started out, some of the definitions of participant funding would have participant funding basically being voluntary.

MS. ZIBELMAN: Right.

MS. FERNANDEZ: And if that's your definition, then what really becomes important is what's mandatory.

MS. ZIBELMAN: Right.

MS. FERNANDEZ: Because the voluntary is left over, and if something is going to be funded by someone as part of the mandatory and part of the plan, then you shouldn't expect a market-driven solution because the market is going to see that it's going to be taken care of in the plan, so it isn't worthwhile for any individual to come in and propose it.

MS. ZIBELMAN: And I would agree that when we're looking at it, particularly if we move forward with transmission companies that are really going to be -- looking at it from my perspective, it's part of my economic growth vehicle, is putting in investment, is, I will look at a transmission needs that solves probably a multitude of problems, including congestion relief.

And we have both binary constraints and constraints that are created by load patterns, and sometimes it's just in the worst times that you have those.

And so we can call them congestion, but I could also call it a real reliability concern, because if I can't import the power during the summer because of a physical constraint, that's going to be a real problem for the load I'm serving.

So I think, in my mind, as you begin again with a robust planning process and you identify, you know, if you're going to build this, if you're going to make this investment, what are the implications of what's going to happen? And you would say, well, I'm doing this because I need a system upgrade because of new generators, but as a result of doing this, we see a binary constraint that occurs during these load patterns, which will be ameliorated by this.

And I have all these reasons that this is going to go in. And then you go again, I think, through the vetting process, through an RTO, and probably through some siting.

And so, in the end, what happens then, what's left, is your question. And I think what should happen is that the RTO, as part of its planning process, should be looking on as sort of, if we do all of this, then what's left? What are the congestions that are not being relieved, and then I think we might want to think about doing an RFP-type planning process where they say we'd like to reduce this constraint and everybody can come forward and tell us what you think we can do about it.

But to me, that ought to follow on a normal-type planning rotation, of what do we think that we need to bring up to get done to cure the issues that we see.

MR. O'NEILL: Can I ask a question? I mean, suppose I'm a large muni in a service territory, and I've decided that I want to go Green, and so I make a huge investment in distributed generation and photovoltaics and all this other kind of stuff, and somebody says, we're going to build some transmission for your benefit, and I say, you know, I don't need it. I've put local generation in. What's your response to me?

MS. ZIBELMAN: Well, the question is, if you're that muni, have you just dropped off the regional tariff.

MR. O'NEILL: No, but I want to be on the system, you know, for various reasons, but I don't need any new transmission investment. Instead of investing in transmission, you know, I've put in real-time meters; I've put in distributed generation; I have some fuel cells, you know, spread around my system, and I say I don't need transmission to satisfy my problems.

MS. ZIBELMAN: And I guess what my response would be that if you want to be -- continue to be interconnected with the grid, then you're --

MR. O'NEILL: You have to cut the wires.

MS. ZIBELMAN: Well, you still want to get something off of it. There's a reason why you want it, whether it's for redundancy or reliability or security, and you want it, and to avoid --

MR. O'NEILL: So your answer to me is, cut the wires, if you don't want to pay for the new transmission?

MS. ZIBELMAN: My answer is yes, either you're part of the game or you're not, but you can't have it both ways. You can't say I want it there when I need it, but I if I don't need it, I'm not going to use --

MR. O'NEILL: I don't need any new transmission. I want to -- I'm fine with the system the way it is. I've made my investment in local generation, so that I don't need transmission.

MS. ZIBELMAN: And I think the answer is that you

-- everybody needs the new -- at least from my -- when I look at it, everyone needs the new transmission because the reason we're building it is the current system isn't adequate to meet the current needs, and so we do need to --

MR. O'NEILL: Is the logical conclusion that all the generators, all the coal generators located at the mine mouth, and all the gas generators locate on the most convenient pipeline, and nobody locates in the places where it's hard, like New York City, Boston, San Francisco, downtown L.A., yadda, yadda, yadda?

MR. HEGERLE: Well, let's ask a generator that question.

MS. BRADLEY: I don't think so. I mean, I think we, Mirant, have always, are locating near the load centers and trying to supply that load.

I guess I wanted to go back and answer the question that Alice asked, which is, I do believe we've got to have a significant planning process. I'm not disagreeing with that or anything else.

Because without that, you're not going to get to what is needed, but you have to look at all the options. And as long as the options are all looked at on the same basis, whether it's generation, transmission, or not, you're going to come up with the right solution.

And I guess I would advocate some kind of -- if it's a reliability-needed improvement, some kind of competitive bidding RFP process like Art was talking about earlier.

So I don't think me, Mirant, or as a generator, is that different than the rest of this panel right now.

MR. O'NEILL: Do you want your new transmission investments competitively bid?

MS. BRADLEY: No, no. Well, sorry --

MR. O'NEILL: I thought I may have misheard. Thank you.

MR. HEGERLE: Scott? Jim? Somebody want to add something?

MR. HELYER: I would agree that, you know, it would not necessarily drive us to locate remotely in every situation. There are other factors that go into that decision besides just the cost of the transmission.

I mean, if there are transmission upgrades that are needed, you know, it may take, you know, some time to get some of those upgrades in, and you may look at it and say, look, I want to get my generator on as soon as I can, and if it's going to take five years, though, to get the wire in the air, if I locate in one location, but I can get to the market.

MR. O'NEILL: It's a timing issue.

MR. HELYER: It could be a timing issue. My point is that there are other factors besides the cost that could drive you to make your decision.

MR. O'NEILL: But I thought there was general consensus on the panel that if you're a generator in a remote location, that's one of the few instances where you clearly would have the generator pay for it.

MR. MEYER: That was, at least, my testimony, and getting back to Dick's question, I mean, clearly a benefit of charging a generator, you know, the fees for not just connecting to the system, but the expansion of the system necessary, is that you are sending the price signal that if you're further away from where the loads are, you know, it's going to cost you more money to do that.

I mean, that is one of the reasons why we've done that in these cases. And going back to your muni example, where I'm arguing that we should -- reliability projects should be rolled in, that I would agree with Audrey that to the extent the muni was depending on the integrated system for its reliability, and we are making a reliability investment, then it would be appropriate that that be rolled into their charge.

If they disconnect from the system --

MR. O'NEILL: So if the local generation was my reliability, suppose I built some redundant local generation for my reliability, should that be rolled in?

MR. MEYER: I would look at it as their choice, as they want to try to disconnect from the integrated grid or not. I mean, they are the ones that are hooked to the system; they're the ones that have signed the contract for that transmission reliability, and then they should pay.

If they don't want to do that, they can take steps, I guess, to disconnect.

MR. O'NEILL: I'm saying that if I want to stay hooked to the grid and I build a couple extra generators locally for my reliability, that helps the reliability of the system, so we should roll those costs into the general transmission, George?

MR. MEYER: I would agree with the first part, that it would help -- it would probably help reliability. Again, if they're still counting on the general reliability of the system, then they ought to be paying for it.

MR. O'NEILL: So that when generators supply reliability, they have to -- you know, that's privatized, and when transmission supplies reliability, that's socialized?

MS. ZIBELMAN: I don't -- when a generator is providing reliability to a local area -- and that's what all the utilities were built up on, is having the multiple generation providing a local area, it's not privatized; it's paid for by the load.

When you're building transmission in order to meet a need, the load can be defined as either the load within the zone or the load within the region. It's still being paid for by the load, so it's all -- the load is always paying.

The issue is which load? And in our view, when it certainly has a regional benefit, it should be the regional load that pays.

MR. O'NEILL: One other question: Why aren't you interested in competing for building new generation facilities that are part of a regional plan?

MS. ZIBELMAN: As an ITC, transmission?

MR. O'NEILL: Yeah, transmission.

MS. ZIBELMAN: My concern is, quite honestly, is that it's taken me 15 years to get anything built, and I don't think adding competition to the mix is going to create -- allow for any greater security that we're going to get things built any better.

I think that it -- and also, we continue to fight local siting issues, and so while -- if I felt like somehow or another, it was going to drive costs down, I would say, yes, it's a great idea.

But I think what it's going to do is put things at risk. And what if, as the person, the carrier, effectively, of last resort, I'm depending on this merchant transmission provider to build, and halfway into the project, they lose funding and they decide not to do it? And as a result, my customers get stranded because they might have been -- we might have then said, well, if they're going to do that, we don't have to do this.

And so I think, again, you know, until we -- and it may be -- one of the things that I do want to add, is, the markets may be at different stages of evolution. What's good for PJM may be great for PJM, but may not work in certain regions.

My concern right now is, we need to get to a certain level of adequacy. And I'd hate to introduce any type of greater uncertainty into the process that would delay that.

MR. HEGERLE: Let me go back to a couple of questions on siting generation. You know, we can call it remotely or we talk about the exports that have been brought up in various scenarios this morning and this afternoon.

What has been your experience in trying to get something sited today? I'll ask the two generators here.

Is the participant-funding-type approach to getting that done, is that preventing generation from being sited? I mean, what's happening right now?

MR. HELYER: I think that in some cases, it is preventing some generation from getting done. You know, when you look at some of the project and what is being required, I think that the issue, although you may think cost is an issue, I think the issue gets back to what are the upgrades that are really needed?

You know, being a planner by trade or what have you, you know, we sit down and have a lot of debate about what is really the fix to the system? If I want to locate a generator in a certain location, is that really a problem? Is it not a problem? Is it appropriate to go solve the problem by building a line from A to B, or can we use some other mechanism?

MR. HEGERLE: Audrey had mentioned something about, you know, when generator comes, you know, it may solve a variety of problems to site when I put that generation, when I build the line to serve that. Is that the experience you have found, that transmission owners have been receptive in that way, or have you had other experiences in siting your generation?

MR. HELYER: I've seen transmission owners be receptive to where I want to locate a generator, and then I have had experience with some that say, you know, look, we think you're in the wrong spot and it's going to require all these upgrades or what have you.

And then when you sit down and you actually go through, I guess that in one instance, we went through a very long process, well over a year, of which initially we were told it was going to be a real problem, and when we got down to it, at the end, it wasn't a problem.

And it just took time to get through the studies and actually go through it, and in the end, you know, it was not a problem, but at the beginning, if we had just backed off and said okay, we believe you, we'll go away, you know, we would never have found that answer.

MR. HEGERLE: You've got to be persistent to get it on the way you wanted to get on?

MR. HELYER: In several cases, you had to be very persistent.

MR. BAYLESS: Our system is between Wyoming and L.A., and we'd love to build more transmission for the reliability of the Utah system. It also helps the rest of the system.

We've had a bunch of people come into Wyoming, wanting to build generation, and we're actually working with one now on a participant-funding credit mechanism.

They want to get into the system and get out to some of the hubs, but it's very expensive to do that. It wouldn't be as expensive to do that if we were to help them with a joint reliability project, instead of projects in Utah and out, but we're not sure how to recover and how that's going to be split and so forth.

We're waiting to see what they do. We'd actually like to build the transmission system, the lines for them. It does help our customers to a degree, but the particular project is going to come into an area that's flush with generation, that unless we get something out of the state and into the system, really can't be depended on as an NR sort of resource.

So we're kind of wondering what to do about it. But we have generators looking to do that; it's just tough to get them over that hurdle.

As far as the munis go, I think if the muni was part of a multistate planning process and could prove to the independent body, transmission provider or whatever, that, indeed, their generation or their distributed generation was such that it precluded them from having to be involved in transmission, they could prove that they weren't benefitting from the reduced market prices, somehow, that would result.

I don't see any reason to cause the allocation not to settle on their access areas, as opposed to others that did benefit. But if they are not a party to the multistate planning function, then we've got to have some sort of reciprocity on how the market is designed around them.

We don't have cut the wires, but there are certainly going to have to be some sort of market provisions at the seams.

MR. O'NEILL: Rich, I assume they were part of the process.

MR. GRAMLICH: If I could follow up on that and explore a little bit more about this Northwest issue, because what we've seen in a lot of -- anytime people have looked at the benefits and costs of RTOs and the whole market system, one of the issues that keeps coming up is the location of generation.

And we've certainly heard a lot about it in the Northeast. Some RTOs or ISOs do have more of system where the generators pay the network upgrades, and others don't, and they have had quite varying results about whether the generators go to the right place.

We heard this morning from SeTrans that that's an issue there that they are trying to solve. Is there a lot of consensus in the Northwest? I mean, you laid out a pretty stark example of building generation in Wyoming, versus towards the coast.

I guess, how much of -- and we don't have a panel, we don't have many of the RTOs speaking here today, but I guess, from your experience, and Chuck's as well, in the RTO West process, I'm wondering if maybe we could break out this piece of this question here.

We've had a day-long debate about what economic investments could be or should be rolled in, versus directly assigned, and that generally covers three main categories: It's generators, network upgrades for generators; it's load pocket mitigation; and it's sort of other sort of high-voltage network needs.

But, again, on the first category, I wonder, since this one seems to keep popping up as a big benefit/cost issue, and a major source of need for new transmission, what is the status of the discussions in the Northwest on this issue, in the RTO West process?

MR. BAYLESS: I think where we are is, as far as once the markets in RTO West are set up -- let me see if I understand this right -- if somebody wants to come in, a generator wants -- load pays, and if -- and it will be the local access fee areas with expansion, open for volunteers to come.

If a generator wants to come in and get to the hubs or get on the system, they can try to do that or choose to do that and they can expand and they can get CRRs or FTOs, in our case, from their investment.

But it's really up to the load-serving areas then to pay any access fees. Now, if their transmission is needed for reserves or something and the transmission gets rolled in, then they can roll in the access area.

MS. FERNANDEZ: I was wondering if I could ask sort of a different followup question. When you were talking before about the construction, you were saying that one of the problems was sort of the risk of recovery.

MR. BAYLESS: Um-hmm.

MS. FERNANDEZ: Is that because you would be building in Utah and the beneficiaries might be in another -- I mean, it is a problem --

MR. BAYLESS: Yes, the problem is multistate allocations, and which state is looking for which customer. So if we build in Utah and can't make a good case that we're getting the dollars back, have problems getting recovery.

So if we had a regional allocation component that was agreed by a multistate entity, of which they would be a party to on transmission, and, you know, we were mandated to build by FERC, we would hope that we would get recovery.

MS. FERNANDEZ: If that was done, say -- does the RTO West incorporate that, or if that was done through the RTO West planning process --

MR. BAYLESS: Right.

MS. FERNANDEZ: -- it was determined it was necessary, there could be assignment to the appropriate --

MR. BAYLESS: RTO West has a backstop provision in the planning process that would do that.

MS. FERNANDEZ: Okay.

MR. MEYER: I was going to address Robb's question. I agree with how Rich characterized what RTO West would do; that it would be up to the generator to decide whether or not they wanted to deal with congestions on a real-time basis, or whether they wanted to try to solve the problem and make the investment.

It seemed like two years ago, as that debate was occurring, as well as our own debate about building the infrastructure for the requests that had been made, the developers or the owners of the generators were -- may have questioned, but rarely questioned the idea that we were going to require up-front funding for those.

It's only really been the last 90 to 120 days as the price of power is down, their credit has dried up, that they have now almost all come in en masse and said maybe it's time to change the policy, and the best thing for the region, of course, would be to get the generation; please roll in our transmission investments.

So the debate has changed. Prices have collapsed and the industry has run out of money.

MR. GRAMLICH: Well, I mean, one might -- if the only thing that were participant-funded on the network were new generator interconnect, you could sort of call that -- that might be labeled as a sort of stick it to the generator policy, but we heard from Mirant and CalPine today, and I think a number of other merchant generators that they don't really see it that way, that they want to get it built, and understand that if they pay for it, it will get built.

MR. MEYER: The other thing, which also gets back to Dick's question, was that most of these generators are located along two different natural gas pipelines, so it seems like they want to -- they're trying to minimize their gas costs and their availability of the fuel supply, more than they're worried about paying the transmission costs.

MS. BRADLEY: One of the things that we're doing up in the Northwest, though, is the IPPs have gotten together and formed this Northwest Independent Power Producers Coalition to kind of explore some alternative ways to get this transmission funded, that we need to, and to get the thermal capacity in there that they need.

And right now, I know the group is meeting, actually today or tomorrow, I think, to talk about maybe some cost-sharing or some different kind of transmission products that would be more appealing, and not totally funded by us.

It's true that if we pay, we expect to get it, but right now, our problem is that we don't have the capital to go out there and do these upgrades. So I guess my answer to all of this is that I think you've got to consider some flexibility in terms of once you've identified a project that needs to get built, that there's got to be a way work together to finance it.

MR. MEYER: That is the same group I was just referring to, and even though we have the policy position of requiring these up-front monies, we are wanting to talk to them, because, again, we think we need some generation to be built.

Now, whether we change our policy or not, I don't know, but that's why we're having these conversations to see if there is something that would be better for the residents of the Northwest or the citizens of the Northwest, than just not having the generation.

MR. HEGERLE: Les? Les, you've been waiting for a little while there.

MR. STARCK: Thank you. I just wanted to address Dick's question of Audrey regarding her views on transmission competition, and I just wanted to say about the FERC proposal in the SMD for transmission competition, it's a market-driven approach. It says that the independent transmission provider would be the clearing house to select between generation, transmission, demand response alternatives, and our concern about that is that each of those particular alternatives are very unique.

They each have their own economic lives; they've got their own availability features; they've got different performance risks, and during that process, for the ITP to select each one of those, to select between those alternatives, that process is going to be contentious; it's going to be long and arduous, and just very controversial.

And we just think that that is going to add a lot of time to the process of getting needed transmission built. We all agree that we need transmission today.

The process to get transmission built today is very difficult, and to superimpose upon it, the transmission planning process that you guys have suggested, we think, just adds to that delay and that uncertainty, and we don't think you need to do that.

You know, maybe some day, somewhere down in the future when we get a lot of these other problems worked through, maybe we want to have a competitive transmission kind of planning process. But at this stage, we think we should not go there, and focus on other problems.

MS. FERNANDEZ: I guess that was sort of a lead-in to one question I had had, based on some of the discussions. It was sort of how or to what extent should non-transmission alternatives, how should those be considered as part of the planning process? I have a volunteer.

MS. ZIBELMAN: Well, I think, again, you know, you have to start from the perspective of where you're coming from. I mean, a lot of the states that were part of it continue to have least-cost planning. It may be gone in other places, but we have that.

And so when, in fact, we need to go ahead and justify need for transmission, just to get a certificate, we have to demonstrate that other alternatives, including demand-side management and generation, how they were considered and how we got to the conclusion we did.

So it will be considered part of both the state's siting process and need process, and I also think that we would do it as part of our own planning process, because we would know that at some point we would have to identify those alternatives and to see what's there. And so you have two levels, and then at the third, I think, at the RTO planning process, when the RTO is reviewing those plans, I would expect their rules to also look at those alternatives and how it impacts other systems.

So, in the end, I mean, I don't think there will ever be a rush to people building transmission when there is a viable generation or demand-side alternative, only because of some of the siting issues that we continue to go back to.

If I can, I'd like to also respond to Dick's earlier question about is this going to result in people just building mine-mouth coal and building along pipelines? I think one of the reasons that we went to this highway zonal concept is that in the supply zone, what we would do is attract generators into a supply zone where there was ample transmission, so you wouldn't necessarily have to build new transmission to send at least that pricing signal.

And I would -- I also think that one of the commentators this morning, I thought, had a very good idea, that when you have multi-regions where generators are located, say, in Wyoming, and they want to move power to L.A. or they want to move power sometimes to Chicago, you're going through probably multiple highway regions.

And I think we do need to take a look at some sort of averaging to make sure that everybody gets paid along the route, which, again, I would send the right economic signals that it might be cheaper to just build the plant in Chicago than to try to build a mine-mouth coal in Wyoming and build a lot of transmission to get it there.

MR. O'NEILL: Now, you raised, I think, an interesting question. You were going to go through a state certificate process to build your transmission, and I assume that going through all of that, the state would not object to having those rates rolled into their customers' rates.

But what about a neighboring state that all of a sudden, you know, became part of this zonal process? How would they get involved early on, so that they didn't get sort of surprised after the other state issued a certificate and all of a sudden, they were responsible for some costs?

MS. ZIBELMAN: I think that as par of this evolution -- and I know that the Commission has proposed a state participation in a regional plant -- we are, and the Governors Conference also identified that need -- we have to evolve there.

I mean, we're not going to have discrete states island'd, and I think the states need to have a planning process, whether we do it through compacts or whether we do it through a voluntary process. Because the last thing I think anyone of us want to see is that we go through all of this nd then somebody else stops it. And that has to be part of the standard market design change.

MR. MEYER: May I respond to Alice's question? We, of course, think that you do need to do the demand-side management aspect, even before you even propose that you're going to go out and do transmission, not only because we have the belief that it is a viable alternative, but we just know that trying to string new wires through green fields can't happen with the not-in-my-backyard people that we have in the Pacific Northwest.

We have got to be able to demonstrate that we have explored all other alternatives before we start putting up steel towers and stringing wire. It just won't happen otherwise.

MR. HEGERLE: Let me ask a couple of questions that might end up being fairly focused. I have one for Audrey: In you local regional rate design, if you decide that a project needs to be participant-funded, does the customer also pay the highway or local access charge as well, or do they just pay the participant-funded amount to get transmission service?

MS. ZIBELMAN: I think this is the same question that Dick asked. I think they may just pay -- they may pay for the upgrade, but they're also a beneficiary of the entire rest of the system, so they should also pay for the access, which is why, again, I think participant funding should be the last thing we look at, because we also know that there are probably free riders on the system that they are paying for.

MR. HEGERLE: Do others have views on a general note to that question, that if you have participant-funded something, and now you want transmission service, do you need to pay the access charge, as well?

MR. BAYLESS: Well, you're talking about a generator coming in on their own hook?

MR. HEGERLE: Whether it's a generator or just a cost-style load, you know, for load growth, for instance.

MR. BAYLESS: Once the market is in place, we were envisioning awarding them with CRRs, so they could -- for the transmission capacity they increase between whatever the points were.

As far as the access fees, if they're coming in just to get to a hub, we're not sure where it's going to go; if they are coming in to be in the re-dispatch market or whatever, they could use the CRRs, if they were appropriate. And you've got the free rider issue.

But if somebody needed that resource ultimately, and we had a load-serving entity, then it would be that load-serving entity in that ITP area that would pay the access fee to bring it in.

If it comes in -- if it's built for competition to replace a generator out there that the load-serving entity already has, that's their choice. But if they fund it, they'd just get the CRRs, and the actual access fee would be paid by the loads.

MS. BRADLEY: I agree with what Rich just said. Basically, if you're participant-funding, you just pay that part, and the load always pays the access fee; that's the way the OATT is put together.

MR. HEGERLE: Any other reactions? Okay, Beth, I had a question for you as well. You mentioned earlier about concern about getting paid back if you did pay for something; that perhaps the CRRs might not be sufficient.

I guess I just was wondering, why would you pursue that investment if that were the case?

MS. BRADLEY: Once again, it's this long-term philosophy versus a short-term philosophy. The CRRs might be there for the first two, three, four years, but then depending on new generators coming in, or somebody else freeloading on the backbone, you're not going to have them there in years four through ten, and you still have this investment you've got to pay for, for x-number of years.

So I guess what we're looking at is that there's got to be another way besides CRRs. It might be the right answer and it might not be the right answer, so maybe the concept of transmission credits or cash or something like that to pay back, is an idea.

MS. FERNANDEZ: I was wondering if you treated it, as you made an investment and it was almost like a property right where you were guaranteed for a certain number of years up front; would that solve the problem?

MS. BRADLEY: Yes.

MS. FERNANDEZ: I mean, your concern is basically that you don't want to find out, because of congestion later on, that what you had been told when you made the investment to be good for ten years, 20 years, or whatever, is no longer true.

MS. BRADLEY: That would be a way to do it, yes.

MR. SCHARFENBERG: With regard to existing customers on the system right now, that's one of NRECA's concerns regarding the allocation, initially of CRRs. And to ensure that existing transmission customers essentially have the rights that they have right now, and to ensure that it's not for some limited period of time, but it's an ongoing -- essentially is an ongoing security to them, that they are protected and have -- are entitled to the service that they have now.

MR. HEGERLE: Audrey?

MS. ZIBELMAN: Just because I know that it will keep me up all night, I need to clarify something. In your last question, if the generator is participant-funding, there are tariff designs. The generator doesn't pay; it is the load, and when you are asking the question, I was thinking if the load is buying from that generator, do they avoid the access fee because they've funded some transmission? No, they would still continue to pay it.

MR. HEGERLE: They pay both, right, okay. Les, you mentioned earlier, when we first got started, you know, that California tried a market-based approach and it didn't work, and you need to go back to something else.

Did they really try that with transmission, or were you referring just to the power sales market and what have you?

MR. STARCK: My understanding is that Cal ISO went off and did a bidding process on the transmission line, and they looked at a number of alternatives to the transmission, including demand response, another market-driven type of approach.

And when they were trying to take a look at each of these alternative solutions to solving a particular need, they found that it was very difficult to be able to come up with the agreements to make sure that they got the service that they needed.

I mean, they wanted transmission service, but they looked at, for example, a demand response alternative, and that alternative may not have been around for 30 years like transmission is going to be, so they needed to work out the fact that the economic life of transmission was a lot longer than maybe this demand response alternative, so they were trying to figure out exactly how would they accommodate, you know, the fact that demand response is a completely different kind of a product, as opposed to transmission.

And that was a very arduous process in trying to work out how they would make that work, and at the end, they decided to do the transmission project.

But by most measures, people felt that it was a difficult and time-consuming process.

MR. HEGERLE: Competition is messy, huh?

MR. SCHARFENBERG: It's very, very messy.

MR. HEGERLE: Kevin, I know you had some questions you wanted to ask?

MR. KELLY: I did have one, and it might have a long answer, so just cut us off when you need to. But for the majority of this panel, you favor rolled in for a large class of upgrades.

But it's not a strict roll-in; it's roll-in here locally, and here regionally, and I think Audrey made a very nice set of examples of how there are multiple beneficiaries. You know, you're hooking up some wind generation, but it helps loop flow over here, and there are many multiple benefits.

The question goes to who decides who the beneficiaries are? Various. FERC could do it, which, you know, we could send it off to our ALJs, that would be one solution. Each stakeholder could hire teams of engineering consultants that could come up with vastly different answers.

You could do it through stakeholder negotiations, dispute resolution. Is an independent transmission provider essential? Does it require a large independent transmission provider, so that you don't have a bunch of little independent transmission providers fighting with one another? What's the mechanism for deciding this basically planning cost allocation beneficiary scenario?

MS. ZIBELMAN: If I could start, I could tell you the way we're looking at it. We have the TransLINK, what we call the TransLINK North Footprint, which encompasses a lot of the former MAPP region.

And based on the load flow analysis that we did when we designed the tariff, we determined that most of the transactions, regardless of the source or the sync, ended up on people's high-voltage facilities in that region.

And so I would think you could do it on an a priori basis when you think about what you're going to roll in on, in our view, what we call the highway, and then on the zones, we basically used the old -- the existing control area zones, although we've blended them to a certain extent, of the existing utilities, and those would become the local zones.

I don't think that you could do it on an ad hoc or afterwards. I think you have to decide this is the subregion highway zone within the RTO, and it could be, in PJM's case, the size of the entire RTO, or, in MISO's case, several subregions.

And then the local zones could be some subpart of that as a control area. What we've done -- why we looked at voltage is that it seemed to make the most sense, because you could define it easily, and then you're never in a debate after that. Do the debate once and then be done with it.

MR. KELLY: Would others like to comment on how you determine who the beneficiaries are?

MR. BAYLESS: We're working on it. We feel that as far as the local access area is, it's pretty clear, since most of those, at least in the transition, are going to be company area rates, and that's a problem for the states.

But we formed a group that's taking that on now, a Seams Steering Work Group, which is a group that brings together, the three RTOs, three or four that are going to cover the West, with stakeholder and Commission representatives, their staff.

And they are hammering that out now. They're working on coming up with the regional plan, and then the problem is going to be that the Governors are going to ask, well, how are we going to finance this and the different methods? And they are looking through, seeing if there are good measurement ways that you could actually look at how the benefits are allocated.

Reliability-wise, we've been looking at that for a long time with path allocation task forces and different ways to see how nomigraphs work and who benefits. So we have been there a lot on some of those issue already.

We haven't got it all figured out yet, but the process has started. We don't think it's an impossible task. We think we can get there. It's just going to take the states and the stakeholders to help us.

MR. HELYER: I guess that we have been envisioning the RTOs having a major say in all of that. If they are going to be responsible for doing a lot of the planning, they are probably in the best position to try to determine, you know, who's doing what.

You know, you are always going to run into the situation, though, as to what timeframe are you trying to make this decision in? If you're looking at it just for the next year, you may reach one decision. If you look out over ten years, you may reach a different decision.

You know, it's not going to be an easy process for anybody to sit down and try to say you're going to be responsible for this, this, and this. But we are, I guess, in summary, looking at the RTO as probably being the driver.

MR. KELLY: Scott, when you said the RTO, do you mean the professional staff of the RTO or stakeholder committees?

MR. HELYER: I guess you'd have the professional staff of the RTO making a recommendation or what have you, based on their ability. You know, if the RTO is truly independent, then it should ultimately get up to the decisionmakers and what have you, and have it decided, but I would tend to think that the technical folks are going to be the ones that are really going to be the folks that are going to have to get there and figure that out and people are going to have to listen to what they have to say.

MS. BRADLEY: I guess I'd like to just add on to what Scott was saying, which is that we saw it more of a stakeholder process that then goes up to the ITP or RTO. I'm using those interchangeably right now. And that's where the decision would be made, and if it's a transmission project that goes across more than one state for siting and stuff like that, then you're back up to whatever regional committee that you've got.

MR. KELLY: But, Beth, maybe I have misunderstood, but I heard you earlier sort of supporting -- I think you said, like, Mike Schnitzer's opinion.

And as I understood him -- and perhaps I misunderstood him -- it was all a market decision. You know, absent these reliability plans, that if somebody wrote a check, it got built, and if somebody didn't, it didn't, and there really wasn't much of a planning for economic expansions or --

MS. BRADLEY: Well, that's where we kind of differ in terms of what SeTrans has proposed in terms of the details we don't agree with, but in SeTrans, we still do have a big planning process that's going to start, and it's going to be ground up with more input from everybody, including the TOs, the merchants, and independent transmission companies, so --

MR. SCHARFENBERG: Because of the difficulties in discerning exactly who's benefitting, you know, we think the focus is more appropriate on who is actually being served.

And if end users are being served within the footprint, as I stated in our position, you know, we believe then that it's appropriate to roll in. But because of the difficulty that's evidenced by this discussion, in trying to determine who should decide who benefits and exactly who's benefitting, it's more appropriate just to focus on who is being served.

MR. HEGERLE: I think we're just about done. I had one clarifying question I wanted to ask, and I know that the Chairman has one question as well. Les, when I was talking with you a little bit about competitive alternatives to transmission and the process you went through and the difficulties there.

I thought I remembered earlier, Chuck, you had talked a little bit about that. How was it that you were able to make that work?

MR. MEYER: Well, we're still in the process of making it work. One of our projects we have identified as a likely candidate to either not do or to delay for upwards of eight years, ten years, maybe longer, and we're involved in a public process right now, working with stakeholders and everyone else to see if others would also agree that they think that can work.

And so you kind of have to stay tuned to see how real it's going to be and whether we get there or not.

MR. HEGERLE: Was that through a competitive process, or something that Bonneville sought to do on its own? How did that come about?

MR. MEYER: Well, it's just a public process we're doing. We had identified the need for this reliability improvement going through this particular area, and we also were aware that we thought, and because there are a lot of large industrial customers in the area, it seemed like it made it ripe for discussing how might the capacity be shifted around.

That is why we kind of targeted in on that area, and then we just basically put out a notice that, you know, we want to involve stakeholders in this conversation about whether or not demand-side or demand-shifting measures would be effectively replaced as transmission.

MR. HEGERLE: Okay, thank you. Mr. Chairman?

CHAIRMAN WOOD: I have a question for less. If we do not include in the SMD final rule, a compulsory RFP first requirement for an RTO's plans, are there any obstacles between what I think your company wants to do in the way of transmission expansions today and actually getting going on those today?

MR. STARCK: In the absence of an RFP process, you mean? Can we go forward today and make transmission investment today?

CHAIRMAN WOOD: Right. I mean, isn't it under the Cal ISO's protocols right now that prevents y'all from making those expansions today? Are there are any?

MR. STARCK: No, there is not, although we're hopeful that FERC will come up with a framework, a regulatory framework that lays out the rules of the road for getting our money back, and addressing, you know, trap costs, and making sure that we have an opportunity to recover the costs that we incur to provide transmission service.

We've had some difficulties with FERC in the last couple of years in terms of getting recovery of our costs, and that makes us a little nervous, as we go forward to invest more in the transmission grid.

CHAIRMAN WOOD: What are those?

MR. STARCK: What are those? Existing transmission service customers. FERC just issued a final order just recently.

When we first became part of the California ISO, FERC encouraged us to honor existing transmission service contracts, and in so doing, we incurred some substantial costs, almost $70 million of additional costs like ancillary services costs and losses that were not anticipated in the contracts that we had with existing transmission service contract customers.

So we were required by FERC to absorb those costs, and even though we honored the existing contracts, FERC said, well, that's something that we'll have to absorb.

That's an example of one of the costs that we've had to eat. So, you know, we're hopeful that moving forward, that those kinds of ratemaking treatments will not be there.

CHAIRMAN WOOD: Can you -- I mean, with the way that the Cal ISO works now, can you actually propose, through their planning process, a needed transmission expansion, or can they, through their planning process, indicate that one is needed in your neighborhood, and you just going on that?

I mean, what needs to happen after that? Just kind of walk me through TO's mindset here, so that I can -- obviously, the theme of the first three panels today is, okay, great, thinking about going forward, but everybody seems to acknowledge that the here-and-now needs a lot of work, too.

So even between now and, you know, March or April, we've got to figure out how to move forward on some of these, particularly where you've got ISOs set up, like you have.

So there is a need either determined by you or determined by the ISO or both, so you need something between Cal ISO or between So Cal Edison's territory and say Arizona. There's a need for some transmission construction there to benefit Southern California.

MR. STARCK: Right.

CHAIRMAN WOOD: Where you do go from there? What do you need that you don't have today?

MR. STARCK: Aside from the regulatory framework that I just mentioned, I think the processes that are in place in California today are adequate for us. I think one of the concerns that we have is that at the present time there is not a real regional transmission planning body that takes a look at the entire Western region that would combine RTO West, WestConnect and the Cal ISO.

I know we're making strides to get to that point, okay. And I think once that gets done, I think that will make the process work better.

But from Southern California Edison's point of view, our primary concern is the regulatory environment in which we operate. And it's not the Cal ISO that's the impediment to us in making transmission investment that we think is necessary. It's just that our senior management is very concerned about making investment in transmission and being assured that we'll have a reasonable opportunity to recover the investment that we make.

CHAIRMAN WOOD: So when you spend $70 million to build some facility, you include that in a license plate rate, or is the Cal a postage stamp rate?

MR. STARCK: Yes.

CHAIRMAN WOOD: The Cal ISO postage stamp rate incorporates that $70 million?

MR. STARCK: We would roll it in. And the way we're moving in California, it depends if it's a regionwide reliability-type project, we would roll it in and it would be applied to the entire ISO grid over time. We're transitioning to a single postage stamp-type rate.

Originally, we just had license plate rates, but we are moving towards a postage stamp rate. That's for those kinds of upgrades that are for regional reliability. We also have local reliability upgrades that we would do that are under 200 kV. Those would be just a local zonal rate. That's how we would pursue those.

CHAIRMAN WOOD: So assume this is the former, this is the regional reliability rate, but it's interregional actually, it's between you and WestConnect.

MR. STARCK: Well, that's a little different. I'm talking about just Cal ISO right now for that regional rate. If there was something that we wanted to connect to WestConnect, is that what you're asking about? I'm not sure exactly what's going on there, Mr. Chairman.

I think what we would hope and expect would be that this regional entity that would eventually merge in the West would reconcile those interests. That is, if there was to be a line that goes between Cal ISO and WestConnect, I think both entities would have to decide, that is WestConnect and Cal ISO would have to decide whether or not there were benefits that would accrue to their particular constituents within that particular RTO and work out the allocation, working of course in conjunction with the regional entity. But then you would see us allocating some of these costs to WestConnect and some to the Cal ISO, to the customers within those regions.

CHAIRMAN WOOD: Based on your experience just doing it between utilities, that's clearly in our mind from our infrastructure study out there that we used in extending the mitigation, it's clear we aren't there yet on that kind of construction.

MR. STARCK: That's correct.

CHAIRMAN WOOD: But how far away -- you're closer to it than I am. But how far away are we from having a system where that decision can get made pretty quickly?

MR. STARCK: Well, as far as regional type considerations, I think we've got a ways to go. I think we have a ways to go. But most of the transmission upgrades that our company has been focusing on mostly are within our footprint. And we're not, you know, at the present time pushing on any particular interregional project, although we do have an interest in going into Denver's Palo Verde II line that would bring power in from the Southwest, and we're looking at that quite seriously.

CHAIRMAN WOOD: But as to the within California ISO upgrades that are necessary, you all can really move forward on those today. Your concern with what exists from FERC is what? You would not under the Cal ISO tariff include the full cost of that $70 million build in the Cal ISO revenue requirement for access fee?

MR. STARCK: We would.

CHAIRMAN WOOD: Okay. And so what's the issue there now? I mean, what's the regulatory overcrowd or hangover crowd or whatever we're talking about?

MR. STARCK: Some of the concerns that we have with the regulatory treatment?

CHAIRMAN WOOD: With regard to such new construction.

MR. STARCK: Oh. Well, with respect to new construction, part of the problem is rate freezes in California, of course. We have to work through that. But we can seek to get a transmission revenue requirement set here at the FERC, and that can happen. And that works quite well, okay.

We do have a concern about rate freezes in California and the timing as to when we can get the cash for that particular revenue requirement, okay.

The things I was mentioning earlier about certain other ratemaking actions that have happened that have been what we would say punitive to us as a result of being a transmission owner, all I'm saying is that just, you know, gives us concern that going forward that we don't experience that kind of pain again going forward.

So we're just encouraging a regulatory framework moving forward for incremental transmission investment that says if you spend a dollar, you're going to get a dollar back, including a reasonable return on common equity.

CHAIRMAN WOOD: Well, I'm very interested that we do that. So please work with us on making that very clear because we need it very built.

MR. STARCK: Thanks.

MR. HEGERLE: Okay. I just want to thank all of you very much for participating today and helping us further our debate a little bit, getting closer to the final answer. We'll try and get started at four o'clock with our next panel.

Thank you very much.

(Recess.)

CHAIRMAN WOOD: We'd like to call the fourth panel together. I see a lot of good friends old and new here. I want to just say on behalf of my colleagues here and our Staff, we appreciate y'all sitting through today on this important issue for us to get right.

It's got a lot of nuances to it that I was not aware of when I walked in with my little well read brief book this morning, and I do always appreciate the live interaction and just want to say it's always fine and appropriate to end the day like this with the wisdom and thoughts from our colleagues who have to actually live this at the front lines.

So with no further ado, I'll turn it back over, say welcome and turn it back over to Mark who's been doing a great job today. Mark?

MR. HEGERLE: Thank you, Pat. I would just like really to say we recognize that the retail customers that you all take care of end up bearing the burden for everything that we do here and all the siting that goes on and all the transmission and everything that's built, however we decide to price it, it ends up coming out of their pockets. And you've been here, at least most of you I think have been here for the discussions today and have listened in the debates we've had up here and the little bit of resolution that we've got and the little bit of progress that we've made.

I really just want to turn it really to you to get your opinions on where do you think we need to be in this regard. And I'd like to start with Chairman Dworkin right here.

MR. DWORKIN: Thank you. I wanted to say many thanks, and I could go on at length, but in the interest of time, I just want to move to substance.

I do want to say I often come down here think that I got some idea of what the right thing to do is and hoping I can persuade folks of that. In this particular case, I want to second what the Chairman just said, which is this is real hard. And there are a lot of places where after thinking at length, talking at length, even gathering a little bit of information, I'm not sure what's right either. And I know that we are going to be a long way from perfection as we move forward.

There are two principal points, though, that I would like to stress and which I do think I've got some understanding of their significance. And if you remember nothing else of what I've said, I guess if you could attach these to what I'm calling dual parity, two kinds of parity, it would help to remember what I want to emphasize.

One is resource parity. And you can give it a lot of names. You can call it least-cost planning. You can call it even-handed, you can call it level playing field. You can call it neutral resource selection. You can call it integrated resource planning. But it's essence is really important, and I regret to say I don't think I've heard enough of it today.

I've seen many very valuable references to it in what FERC has said in the SMD in 2000 and several other places, but in practice, when people get down in detail to talking about how they're going to share costs and how they're going to assign costs, there's an awful lot of emphasis on what to do with various kinds of transmission and very little attention to paid to what to do with any of the alternatives to transmission.

And before I go on to my second parity, which is what I'm going to call historical parity, I want to spend a minute on the resource parity question. And I'll move through it in a couple of ways, but first with a tip of my hat to either Ronald Reagan or Tip O'Neill. I'll do it with an anecdote which is sort of local, because I think Ronald Reagan taught us that anecdotes help us understand things, and Tip O'Neill said that everything is ultimately local.

So I'll give you an example. But although it's an example, I want you to understand that I think it's broader in its application. Northwestern Vermont is one of the constrained areas in New England right now. Sometime in the next couple of years, the transmission utilities and the generating utilities, which are vertically integrated in Vermont, are going to walk into the Public Service Board with a plan to try to ease that congestion. And I don't know whether we'll approve it or not. It is all the reservations I need to make as the decisionmaker. But let me just outline the kinds of things they're talking about.

They may want to spend $150 to $200 million on putting new transmission in. Or they may want a mix that has $100 to $125 million of transmission and it has a couple of small generating units so that they can offset each other for reliability dropped into the constrained area. And it has, you know, several million dollars worth of efficiency, and the generating units might be either distributed generation or investor-owned, or they might be sited in a collaborative with some large users in the area.

Lots of possibilities. Let's just assume that the transmission solution would cost $200 million. And let's assume that the alternative, the blend of everything else, would be $150, $125 in transmission, and a bunch of other stuff blended in. If we need to make a decision in Vermont knowing that under pooling rules, we pay 5 percent of the transmission and 95 percent of it is shared throughout New England, but that we pay 100 percent of the efficiency, 100 percent of any generation to avoid a constraint. We have what you might well call perverse incentives. It's not healthy.

We're not alone. Every other state is going to be looking at some kind of situation like that too. And if you've got a situation where some resources are pooled and others aren't, you are distorting things. And I want you told that anecdote if you will, that hypothetical, with that very real hypothetical in mind when you think about how we need to look at moving forward.

In this context, I want to be real clear that this is not an anti-transmission message. I think that transmission is extraordinarily valuable. I've seen the value of the FACTS machine being put into Vermont, very high value. In my role on EPRI's Advisory Board, I've seen real high value to transmission upgrades, particularly technology upgrades within the existing right of way.

But although I think transmission is highly valued, I don't think it is infinitely valuable. And I know it's tempting to say it's been underinvested in, it's not a big portion of total cost, let's not analyze it to death. Let's just put it in place. I want you to know that in the last five years in New England alone, the pool transmission facilities alone, just the portion that was pooled, added to a third of a billion dollars, $327 million has been invested in New England by the utilities in transmission upgrades since 1997.

It's a big number, and I'm infinitely aware of it, because Vermont has picked up 5 percent of it already.

The value of that I think is real, but it's not infinite. That's why I think when you're talking dollars in that range, which to put it in perspective are a lot more than the possible benefits of the merger of New York and New England, when you're talking dollars in that range which are going to be collected and paid for to a mandatory, socialized, essentially a tax on the wires charge, you need to have a mechanism for making sure that you only do that if it meets a couple of tests.

One of them is pretty straightforward. It should be a lower cost solution than any alternative.

Another one is, the alternatives ought to have the same chance for recovery that it does.

The third one is, it ought to have regional benefits. You shouldn't spread stuff over the whole region unless you can see some benefit to the whole region. We should be moving towards some serious version of a test that says we direct assign, and you can call it participant funding if you want, but it's the direct assignment that's the key, as much as is possible given the analytical capabilities that we have, which are serious constraint. And given the fact that we don't want to deter stuff which is good for the region as a whole, and which meets that least cost and parity test.

Here's where I want to move to my second parity, historic parity. As I mentioned, New England has spent a third of a billion dollars in the last five years, most of it in the last two years, on transmission upgrades. As it happens, it won't surprise you to know that that was not spread evenly among the six New England states. It was spread in a few states where the need came forward first, and it will be being spread int he future in other states.

I think most of you have a copy of something that I handed out which shows Vermont's perspective on this. I want to be really clear that there are a lot of perspectives. There's nothing magic about this. But I think this shows the importance of history. If you look at it, you can see that for each year for five years, some states spent more on transmission investments and collected it from the pool. Other states spent less on transmission investments and made payments into the pool that were greater than what they took out. And Vermont, over a five-year period, but in $5.2 million more than it took out. In other words, Vermonters helped pay to the tune of $20 per household for -- and I'll turn to Paul in a minute -- transmission investments which will greatly relieve congestion in Boston for the next decade.

Was that worth it? Maybe we could direct assign better, maybe we couldn't, because that really is regionally beneficial for everybody. But what's critical to know is that if we stay on the same kind of rules we had before, that kind of investment in Vermont would be recovered out of the pool in the next five years, and in the ten-year period covering the pool transmission facility, PTF tariff that NEPOOL had, Vermont would have come out even for the period from 1997 to 2007, as in fact most of the region would.

But if you do a flash cut halfway through, when some states have already had their turn at what I'll call the common trough and other states have not, you have an equity problem which is very real.

And there are several ways you can deal with this. You could, to quote what Jed Bartlett said in West Wing last week, just give it back. We could get back the $5 million that we put into the pool. That would be fine. It would create an equity and we could move forward. Or you could have a transition mechanism that sustains it until you get an equitable balancing of what has and hasn't been put into the pool, which frankly is probably pretty traditional. It's the kind of thing we've had.

The only problem with it, and I think it's a necessary problem to deal with, is to make sure it doesn't undercut the effect of localized marginal pricing in the next few years while you do that. And I think you can come up with mechanisms to make sure you can, given the dollars that are at stake. But I think you have to. Otherwise, you create a very significant inequity.

Having said that, which is a point where you're going to see some difference within New England that I could either call a difference or we have not yet reached agreement on how to deal with it, I think there's substantial agreement that we do want to move towards allocating transmission costs directly in a lot of the circumstances.

Most of them are relatively straightforward. Generator interconnection standards, for example. As I said, New England has spent a third of a billion dollars in the last few years on pool's transmission facilities. In addition, we've spent a lot more money on generation connection which hasn't even been put into the pool. And I think that that's not only good policy, it's existing policy, it should be sustained. And it answers roughly half of the questions on your list.

Other ones on the list we can go through one at a time maybe after I've given other folks the chance to talk. But I do want to get across the idea that if you don't do any assignment, you have a real problem. You get the 700 megawatts in Maine that really can't reach the rest of New

England with no signal that tells them where they should be built next time somebody's thinking about that kind of investment.

But you also have a pragmatic problem with trying to do the assignments. And maybe it was Dick O'Neill who a little while ago said who should decide who is the participant or who is the beneficiary. I picked up when I heard it, because a few years ago I was the mediator asked by half a dozen Vermont utilities to mediate a dispute that had been in FERC for 13 years about a small transmission upgrade involving half a dozen munis, one co-op and two investor-owned utilities, where the line would go between two of them, but the primary benefits would be reduced line losses on several others that weren't even within 10 or 15 miles of it, or physically connected.

Answering that took a couple of things. It took some significant help from a FERC ALJ, Judge Silverstein, who I want to praise and thank for it. But it also took about four hours stuck in a snowstorm with people who had nothing better to do then finally work out a rough cut number that in no way was analytically precise.

Being the mediator in that process for about four months taught me that our analytical tools for figuring out who is the beneficiary of a transmission upgrade are quite weak, and our ability to predict who will be the beneficiary ten years down the road are even weaker.

So that I want to give a pitch to assign as much as you reasonably can but to say meet a parity test. When you assign as much as you can, recognize the limits and costs of further analysis, and make sure that as a matter of just plain fairness and equity, you build in some recognition of historical parity to make whole those who are on the sticky end of the stick, if you will, halfway through a process that we are changing in midstream.

MR. HEGERLE: Chairman Vasington.

MR. VASINGTON: Thank you. My name is Paul Vasington. I'm the chairman of the Massachusetts Department of Telecommunications and Energy. I just want to thank Chairman Wood and Commissioners Brownell and Massey and the Staff for hosting this session.

Chairman Wood and Commissioner Brownell know me as the telephone guy, so they know this is hard for me to sit through this for a day. But I did learn an awful lot, and I really do appreciate this kind of session. The level of outreach you all have had to state regulators and your willingness to listen is unprecedented in my experience, and it is appreciated.

I'm going to focus on the question of the appropriate cost allocation mechanism for transmission expansion within standard market design. The Commission knows that New England has engaged in this debate already over the past few years and has itself issued some orders addressing a lot of these concerns, so a lot of this will probably sound familiar.

With a congestion management system based on the use of locational marginal pricing, costs to expand the transmission system should be allocated in accordance with the benefits of that expansion. This is true whether the expansion is labeled as congestion-related or reliability-related.

To the extent that the entire grid benefits, then that portion of costs should be socialized across the grid. But to the extent that the benefits are localized, then the costs should be borne locally.

The purpose of LMP is to manage congestion by providing efficient price signals and assigning cost responsibility to the cost causers. Allocation of the cost of transmission expansion should follow the same principle. Otherwise, what is the purpose of LMP? Socialization of transmission expansion costs on the basis of arbitrary voltage levels or other legacy classifications such as pool transmission facilities in New England, is inconsistent with LMP and should be rejected in favor of a system that aligns costs with benefits.

The Commission previously has recognized that a system that socializes costs related to transmission congestion does not send price signals that would encourage the siting of new generation in congested areas. LMP is an appropriate mechanism for sending price signals for the efficient siting of generation units. LMP does not socialize congestion costs, but allocates the cost of congestion to the parties who cause it.

Similarly, the Commission has rejected the socialization of transmission expansion costs in New England, repeatedly requiring NEPOOL and ISO New England to come up with an allocation mechanism for the costs of transmission expansion that assigns the cost of the upgrades to those who benefit, to the extent that they can be identified, whether the upgrade is classified as an economic or a reliability upgrade.

This is not to say that where local beneficiaries have been identified, there is not also a component of regional benefits to transmission expansion. It is wholly appropriate to regionalize transmission expansion costs to the extent that they produce regional benefits.

While the current PTF test for socialization in New England recognizes regional impacts, the PTF test is not a location-specific cost causative mechanism. Because there is no identification of local beneficiaries, the PTF test is not consistent with LMP, a system that translates transmission congestion into location specific prices.

LMP requires a local determination of transmission expansion cost allocation. The PTF test does not satisfy this requirement. I understand that the identification of regional and local benefits is a complex determination, but we shouldn't retreat from sound economic principles because the resolution to an identified concern is complex from an engineering perspective. Care must be taken in modeling the appropriate assumptions. Even a very rough estimate of the right outcome is better than a known inaccuracy.

To the extent that LMP provides appropriate price signals for the efficient siting of generating units, a transmission expansion cost allocation mechanism that recognizes local impacts is also necessary in order to identify the beneficiaries of transmission expansion.

Now that NEPOOL and ISO New England are implementing LMP, starting most likely in March of next year, parties will be able to see more readily which areas would most benefit from transmission expansion and allocate the costs accordingly.

Other schemes founded on arbitrary criteria could create an incentive for individual regions to avoid making tough decisions on siting generation and demand response in the hope of having their problem earn the label of transmission reliability, so that the costs of the solution are then spread out over an entire region.

For example, we have experienced significant congestion in Boston over the last few years, some of which has already been alleviated by the investments that Chairman Dworkin already mentioned, reducing congestion costs already for everybody in New England, which up until March of next year have been and will continue to be socialized.

But we've also made difficult political decisions to site 2,500 megawatts of new generation within the Boston area since 1999. I'm now hopeful that this new generation will help us to relieve congestion in Boston going forward.

But what if we had not made those difficult choices? Would we then have a reliability problem that entitles us to argue for socialized cost allocation of transmission upgrades to fix our self-inflicted problems? I think not, but that is precisely the type of situation that may be faced if transmission expansion costs under LMP are not allocated in accordance with who benefits from the expansion.

In other words, we have a problem if there is a disparate cost treatment for different solutions to the same problem.

In summary, under SMD, transmission expansion planning, regardless of cost for the expansion, must include a determination of regional and local benefits, and a cost allocation mechanism that apportions the costs based on this determination is necessary.

In situations where the parties cannot agree as to who benefits, an objective, nondiscriminatory default cost allocation mechanism that is consistent with cost causation is necessary, as the Commission has already required several times for New England. This is the only type of allocation system that would be consistent with the goals of the Commission congestion management system in standard market design.

So the issue to me is really what system for allocating these costs is consistent with the new efficient price signals that will be sent under standard market design. But if there's an initial concern about equity as raised by Chairman Dworkin, that to me is much less important than making sure we get it right within the framework of the new system which seeks to monetize the congestion costs and the value of the transmission system through price signals.

If the issue is in a transition, we need to square past experience before we move forward into a new one, I don't have much a problem with that. The magnitude of the expenditures over the past six years in New England on transmission expansion, Michael mentioned I think it was

$327 million as being the amount that's been spent since 1966, is half of what is planned right now in New England over the coming years.

Under the RTEP process, the Regional Transmission Expansion Planning process in New England, we have $891 million of transmission expansion planned for the coming years. So if the issue is squaring the past but making sure we do it right going forward, I'm okay with that.

And thanks again for your time, and I look forward to questions.

MR. HEGERLE: Commissioner Bratton.

MR. BRATTON: Thank you. It's a pleasure to be here with our colleagues from the FERC and the FERC Staff that's participated in this meeting. I'll have to say that earlier panels today have been very helpful.

I did not bring any prepared remarks, but a couple of observations. Those of us in the Southeast started looking seriously at participant funding two or three years ago when it became apparent that a great deal of gas-fired merchant generation was likely to be located in the Southeastern states for various reasons, and that that generation would far outstrip the demand for it in the south, even if it were to displace older, less efficient units.

Therefore, it seemed apparent that, at least in the minds of those who were constructing the generation, it was being planned for export, or at least a substantial amount of it was being planned for export from that region.

As we began talking with our utilities about the potential cost of transmission expansions that might be necessary to facilitate that export capacity, it became apparent that while as a general rule, transmission is a relatively small part of the delivered cost of electricity, that it has the potential to be a very significant impact for customers of our utilities in the Southeast.

Therefore, we began to seriously explore participant funding and concluded that it clearly was a method for funding transmission expansion that made sense, given our scenario, at least as we saw it developing in the Southeast.

What has been interesting today for me is to hear that participant funding has an important role not only in the peculiar circumstances we find ourselves with in the Southeast, but also in peculiar circumstances in New England, in peculiar circumstances in other regions of the country, that members of other panels have talked about previously in the day.

I think it has broadened my perspective to see that participant funding, while it may not be the appropriate method of funding transmission expansion in every situation, it certainly has a key role to play in dealing with a number of different types of problems in a number of different areas in the country.

Having said that, a couple of things that I've heard earlier today that I think we do need to pay careful attention to, comments from the representative from Calpine and the gentleman from the East Texas Co-op expressing concern about the possibility that under participant funding, projects that should have already been built and have been delayed for various reasons now will attempt to be assigned in a way to directly assign those costs when previously they should have been built and perhaps rolled in.

I think that needs to be given a very careful look in individual situations to see that that sort of potential abuse of the system does not occur.

I think it's also important for us to realize that for participant funding to work and to be perceived as fair, you will have to have a truly independent planning process in the RTO or the ITP -- I use the terms interchangeably.

The Arkansas co-ops, among others, have expressed some concern in the comments they filed at various phases in the SeTrans process that projects for transmission-dependent entities such as most of the co-ops are, unless the process was very fair, might tend to be the participant funding cost-assigned projects, while other projects received the rolled-in treatment.

Again, a completely independent and fair and inclusive planning process and decisionmaking process by the RTO I think can go a long way toward addressing those concerns. But those concerns are out there, and I'm sure you're aware of them.

With those remarks, thank you for the opportunity to be here, and glad to participate in the discussion this afternoon.

MR. HEGERLE: Thank you. Commissioner Baez.

MR. BAEZ: Thank you. Good afternoon. I too want to thank Chairman Wood and Commissioner Massey and Commissioner Brownell for having me here. I don't have any prepared comments either. I think this was, at least I was told that it was more of a reaction. And I think a lot of what Commissioner emeritus Bratton said really strikes a chord with me.

One comment out of hand I think. I heard a lot of several mentions of the higher good among the previous panels. And one went as far as to identify the higher good as competition. I guess from a state regulator standpoint, I have to take exception with that.

Sitting here, I wouldn't presume to tell anyone, certainly at the FERC, their job. But I will tell you what my job is, and my job is to look out for the ratepayer. Not on a best deal basis, but certainly to look into the best interests on that end.

Sometimes that takes hard choices, and many of the hard choices are to be had when we're discussing certainly transmission policy and how the state commissions are going to involve themselves or have involved themselves and discharge our responsibilities on that end.

I was surprised in listening to the panelists as well as to actually how much consensus there really is. It may not have sounded like that at times hearing divergent perspectives, but one of the things, and I think Sam mentioned it earlier, one of the things that I was able to have in a more concrete sense in my mind was exactly where the lines -- you know, there are some absolutes, at least that I heard.

For instance, expansions that are clearly reliability related, I don't think to a man or a woman, anyone disagrees that those were absolute candidates for rolled-in pricing. And I know that certainly many of my colleagues in the Southeast which have been perhaps the region that has had the most concern over this, or at least expressed it publicly, would agree with that fact.

I mean, there are shades. There are no

absolutes. certainly at least in my mind, something that could be classified as for export, an expansion that was clearly tied to an export function in my mind would be something better left to the market and better left to direct assignment.

Now I also heard a lot of -- the notion of allocations within allocations. That's the gray area that I think becomes obviously the most difficult part. But I think even those types of determinations can be reduced to some formulaic determination, because I will recognize that there are benefits on both sides. There are benefits that are to the entire system and certainly benefits that are going to be to the quote/unquote "cost causer".

I would look for, as a suggestion if nothing else, I would look for an analog to the telecom industry. There are principles such as caller pays. And while that may not be a direct analog in the sense, some of that type of logic may be applicable here. And I would urge the Commission to look and the Commission Staff to look along those lines and think along those lines if they haven't already done so.

Someone said that we had strayed into planning, and I think it deserves mention here as well. And I think again, Commissioner Bratton had mentioned it also. I think there has to be a focal point for those types of determinations. I think at the planning level, we're going to come up with certain litmus tests or certain benchmarks or yardsticks by which to make that ultimate determination on allocation. So I think that it rightfully takes place at the RTO level or whichever alphabet we're using at this point in time. They do change rather fast.

But anyhow, we do need a focal point. I think the most appropriate focal point is certainly at the RTO level. And consequently, I think the determinations, at least in large part, of what is a candidate for participant funding, what is a candidate certainly for systemwide rolled in, the rolled-in notion, will become clearer on that level.

And as I had said before, I think some serious thought has to be given to that intermediate gray zone where there is some sharing that may at times be appropriate.

All of that has to take place in a body or an entity that has independence obviously and that doesn't have a vested interest in one result over another, and I think that that most appropriately will be the transmission organization.

That's the balance of my comments, and I look forward to some discussion at the end.

MR. HEGERLE: Thank you. Vice Chairman Gary Gillis from Kentucky Public Service Commission was scheduled to be with us today. Martha Morton is filling in, so I'd like to ask for her comments next, and then we're going to go to the telephones to get a couple of commissioners who are with us by phone.

MS. MORTON: Thank you. I don't have prepared remarks either, but we filed comments yesterday, and I'll just summarize the points that were in it.

Our position probably isn't a surprise to you. We pretty much prefer participant funding. We're opposed to socializing the costs of the competitive marketplace by the monopoly elements of it. I think it should be self-sustaining. And if there's a desire to socialize it, we think that there should be more proof to prove that that's a good thing to do, and not just assume that it's a good thing to do.

And in fact, even if it is desired to socialize it, I think it's more appropriate for tax dollars to socialize rather than try to tax people through the utility rates.

We generally in Kentucky take a very dim view against trying to impose hidden taxes on utility customers to the extent that we can, and you probably know how difficult it would be sometimes to do it. But I think it really has contributed to our low rates by doing what we can to avoid that.

Specifically, our comments that we filed in the I guess pre-NOPR laid out our feelings that, as a matter of equity, the congestion revenue rights need to go to those who pay embedded costs. And we think that's a very overarching principle that needs to be met by whatever we do and that, I mean, just to continue the equity.

But when you dig down into the details and start looking at LMP and the incentives to build transmission, I think you really have to do that to get people to build transmission. If you're going to ask them to pay for something, you've got to give them something of value for that. And about the only you can give them is that congestion revenue right.

You can also use it, you know, when we go forward from the old system to the new system, I think we can all agree that reliability is one of the things that we want to carry forward and we won't sacrifice that or throw the baby out with the bathwater in the new system.

And you can also use that around the CRR approach. You could say that that is a reliability concern if you're unable to deliver the promise you made by giving somebody a CRR. That's a reliability concern. And that if somebody doesn't hold a CRR, then we should not worry that their transaction was curtailed or that they had a congestion cost because they didn't pay the hedge for it and they didn't -- they haven't paid anything to receive anything of value.

So I think if you start from a logical viewpoint and start developing it that it will make your decisions a lot easier because you set a goal there and incentives for people to do what's best. Incentives and stability both are things that I think we strongly need here. And you can also by granting the CRRs to those who pay the embedded cost, you can guarantee that they'll keep those CRRs. You'll keep a little bit more certainty, give people more certainty that when they make their investment that they're not throwing money away. It really boils down to you need to give them a feeling that they're getting something for their money.

And on another point, determining beneficiaries of construction, again, the beneficiary is the one who receives the CRRs. They're the ones who receive something. The difficulty in determining like allocating a particular transmission line into CRRs for those who paid for it is a process that like MISO is doing now to try to allocate the transmission rights for the existing system. You know, use a flow-based model.

You can take a transmission line but like in the case with the 500 kV transmission line that she mentioned that it wasn't fair for customers in Ohio to have to pay for that. Well, under the LMP approach when you have to take the network service and break it down into a set of point-to-point rights, that's where you get your CRRs from, the people in Ohio wouldn't have CRRs for that 500 kV line, so they wouldn't be paying. Because if you link the embedded costs to the CRRs, they wouldn't be paying for that 500 kV line.

So that just more or less summarizes our position. If you have any questions, I'll be happy to answer them.

MR. HEGERLE: Thank you. And I have to ask Commissioner Mettner to forgive me. I misread my list. So if I'd allow you to go next and then we'll go to the phones.

MR. METTNER: That's okay. I thought you were jumping around according to some predetermined list.

(Laughter.)

MR. HEGERLE: Yeah, that was it. That was it.

MR. METTNER: All right. I also would like to thank the FERC Commission members for inviting state commission members to share some thoughts and viewpoints at this technical conference today, respecting that there might have been easier days other than right after the elections. I don't know how much any of you have slept yet.

I have a few jotted down remarks that I'd like to share. I also would like to say that as a Commission, we're going to more completely participate in the comment process for this. I'm speaking a little bit on my own, a little bit in conjunction with the help of other people who help me put together some thoughts for today. But I speak sort of parochially from the Wisconsin perspective.

I know that Commissioners Brownell and Wood do have a background of doing some degree of phone regulation. Commissioner Massey, I don't know if in a past life you ever did any phone regulation, so forgive me. One of the models I would commend to your attention not to use in trying to, with all due respect to one of the comments that you've made, in trying to approach all this is the jurisdictional separations model used by the FCC.

I've been on the FCC's Federal-State Joint Board on Separations for a while now, and my original academic training was as a tax attorney. And wading through the separations practices and procedures makes the tax code like a merciful respite as far as reading it.

(Laughter.)

MR. METTNER: And I think one of the problems there is they started out in an attempted fairness to separate cost causations of various assets into a federal and a state jurisdiction, but the process sort of circled back on itself many different times.

And trying to directly assign assets to one jurisdiction or another based upon what is presumed to be the underlying use of it and then trying to separate those things that have a mixed characteristic into traffic-sensitive and non-traffic-sensitive aspects of it, and then to reach political compromises for certain of those elements on a 75 percent/25 percent basis, and I think you see where I'm heading.

It becomes very Byzantine, and the analogy was once given to me by somebody who actually did this as a career, and I would say be merciful to your Staff and not make them spend part of their career doing something like this, is an analogy that's designed to say that the underlying purported precision of the system really does not justify the sort of blunt-end results that come out the other end that sometimes are a bit perverse.

The gentleman explained it to me that it's like measuring to the micron level with the calipers, marking with a piece of chalk and cutting with an axe.

(Laughter.)

MR. METTNER: And it makes you wonder what the useful precision in the front end really created. And this is by way of saying that the methodology you use for whether it's funding of congestion mitigation or assets that produce congestion mitigation or transmission pricing issues in general, they should be made to be fair and easy to understand by people who are planning the system. And I think that that is especially true in the long term.

As a state, we view participant funding -- and I realize that that term means different things to different people. Some people use the phrase "participant funding" to mean something of a presumption that an asset should be dealt with on a participant funding basis unless somebody can demonstrate otherwise. The previous speaker I think would fall under that category.

Other people realize participant funding may be indicated for certain assets but on an exceptional and not a presumptive basis. I suppose I would fall more into the latter category. And that's because in addressing what is clearly a congested transmission system within and without our state, the state of Wisconsin, we realize in looking at various transmission planning exercises and transmission construction certification proceedings that all but the exceptional project produces some systemwide benefit. And we saw that particularly to be true as we went through the record in the Arrowhead Westin transmission line cases and the Shesago transmission line cases.

I think presumptive participant funding is potentially the most dangerous, to the second concern that I think you have to keep in mind as you're looking at the economics of it, which is the signal that it sends to people who need to plan, construct and operate the congestion alleviating assets that are necessary to improve the reliability of the system so it can match in terms of its physical capability what in many cases were the aspirations for its use in Orders 888 and beyond.

The impact of these on load-serving entities I can't emphasize nearly enough. The load-serving entities have to be able to serve their customers on a firm basis. I think the solidity of that should be front and center. It should be the primary focus I think that anybody purporting to change rules, alter them incrementally or otherwise should think about.

I think sticking to traditional ratemaking methods and relying upon cost causation, I think that there are power flow methods -- I've seen computerized models -- that can, to the greatest degree possible I suppose simulate power flows and how the system is being used.

It would be uniquely cruel to a state like Wisconsin to have -- and I realize that this is present company excepted, possibly with the exception of Commissioner Massey -- but Order 888, you've heard this time and again to the point where it's hackneyed I think for all of you -- Order 888 and beyond resulted in the transmission system being used in ways it was never planned and constructed and operated for in years prior.

And so states like Wisconsin have found that as certain of our reliability in the increment has been compromised by parallel flow issues. And then to construct to alleviate those constraints and then have the costs allocated to that on a participant funding basis seems to add a certain degree of insult to injury.

A lot of the constraints that we're experiencing right now, especially with the Western Interconnect, which various power studies have found one of the most constrained power lines in the nation, we have to construct to alleviate those constraints. And I don't like the signal that participant funding would send as an incentive or more likely disincentive to people who would be able to plan and construct for that.

I think that the focus should be long term, as I've pointed out, with respect to planning pricing and the signals that it sends to people who operate the system.

I'd also express a skepticism if not a cynicism toward the concept of merchant transmission. It seems to me that one of the most difficult aspects of merchant transmission are the underlying purposes for which the merchant gets in the game or gets out of the game, and also the fact that, at least under our current statutes and probably most of those of the jurisdictions represented here today, the merchant transmission owner probably wouldn't possess eminent domain. And anybody who has sited a long a difficult project and a controversial project knows what a nasty aspect it could be if you didn't have eminent domain to go back on.

Increasingly, we have found that projects that have to rely upon actual condemnation to really construct across a property without getting a voluntary or consensual easement from a property owner adds to the incremental cost of the transmission project astronomically, in many cases making it not economic.

I think that the long-term focus also matches the planning horizon that people who construct generation are relying upon. Generation is going to be a 20, 25 or 30-year investment recovery asset. And I think you have to think about that with the transmission system in mind. And I mention this in conjunction with the merchant transmission idea again because of their motivations is that it is tempting to try to let markets do things and say, well, somebody will move to a congested area, and where it's in their best interest to do so, economic self-interest to do so, will construct to alleviate a constraint.

I don't think it's ever going to be in the best interest of somebody who owns merchant transmission to alleviate the constraint completely. They would lose that aspect of their sort of toll bridge advantage with respect to those particular facilities. And so I think you might find some incremental solution, but I don't think within merchant transmission you're going to find long-term, effective solutions.

The second area I just want to touch briefly on and commend your attention, we've been studying and find some desirability in what has been called the TRANSLink pricing concept where the system is broken into sort of highway pricing zones generally represented by high voltage transmission lines. In some cases, there may be a distance sensitivity figured into the pricing for the highway pricing or high voltage part about that. And then local zone rates that are divided into generation and load zone rates within those local areas for the lower voltages.

I could get into the detail of that, but I know TRANSLink has got a complex set of filings in front of you, and I don't want to reiterate them. I would only circle back and say that that TRANSLink concept as it has been demonstrated to me and will be before you on a continuing basis, represents a sort of first principles of cost causation or an attempt at it with respect to pricing transmission services across a number of different regions.

I simply commend it to your attention as something very worthy of your consideration.

And finally, the issue -- I realize I'm probably getting a little bit outside the bailiwick of today, but issues of planning and the responsibility for planning I think should always carry with it a ground-up component to it. As long as the states remain in the business of siting and have to as state commissions and commission members give thoughtful consideration in certification proceedings to the arguments people make before us, I think some planning should be done.

For example, I think you had a witness, Mr. Landgren from the American Transmission Company. They make a very thoughtful argument I think for their role in the ground-up planning whether planning as a stand-alone transmission company or working in conjunction with something like an RTO or the Midwest ISO.

And I just think that because siting right now is intrinsically a state localized type of thing and the responsibilities for putting out these projects are with entities like the American Transmission Company, that they have a unique and specific focus on planning and a meaningful role to play.

Thank you very much.

MR. HEGERLE: Thank you. Now we're going to try and I hope we still have Chairman Hemingway available on the phone, if you can hear me. Do we still have him on the phone?

MR. HEMINGWAY: (By telephone.) Yes, I can hear you.

MR. HEGERLE: Terrific.

MR. HEMINGWAY: Do you want me to comment at this time?

MR. HEGERLE: Yes please.

MR. HEMINGWAY: The only comment I wish to offer is to second Commissioner Dworkin's concern that he expressed as his first point about being able to be sure that we have a real choice among alternatives other than transmission.

My concern about RTOs from the beginning has been that when every problem looks like a transmission problem, then there will always be only transmission solutions when there may be very many lesser cost solutions that involve energy efficiency demand response or distributed generation, or even central station generation.

And one of the things that we're trying to do in the West in response to FERC's invitation for us to come up with a Western response to the SMD NOPR is to try to find a way to get publicly responsible and timely planning done that would allow -- give decisionmakers these options well in advance of need.

One planner for one of the RTOs, I believe it was WestConnect, opined that they would do all the transmission planning and then if someone else came up with a better idea, they would look at it. That doesn't strike me as an appropriate process for making, as Mike Dworkin suggested, the various options equal in the planner's mind and have them equally staffed out and developed so that we can figure out the best and least cost option for ratepayers.

The SMD NOPR and the RTO orders so far have been quite silent on that subject, I think as Mike noted. And we take that as an opportunity to develop a process that will get these issues on the table, get alternate possibilities to transmission on the table in a timely manner so that they can be judged and the least cost and most efficient solution implemented.

That's all I really have to add at this point.

MR. HEGERLE: Thank you for those comments. I should have said that's Chairman Roy Hemingway from the Oregon Public Utility Commission.

I also hope that we have Chairman Donald Downs from the Connecticut Department of Public Utility Control. Is the chairman there? Can you hear me? Chairman Downs?

(No response.)

MR. HEGERLE: I suppose not. Perhaps we've lost him. Was he not on earlier?

VOICE: He wasn't on before.

MR. HEGERLE: Okay. He was scheduled to be here. Okay. We'll see if we can't get him. In the meantime, if we could move to staff representatives from the state commissions, I'll start with Mr. Proctor over here.

MR. PROCTOR: I'm going to try to keep it kind of brief. As I've been sitting here today trying to digest all of the different concepts related to reliability transmission, economic transmission, trying to figure out how that fits in, feeling at times that people were talking past one another still, so I'm not convinced we're all there.

I'd like to put forth something very simple, and I hope it's helpful. And it's just the way that I guess we look at transmission, transmission expansion in Missouri. The interior load customers within a control area -- and I'll call it a control area. I probably won't be able to do that for much longer. But the utility plans transmission for those customers on a forward basis. And that has to do with both the customers that they serve as native load and as well those customers who are not their native load customers, customers who are strictly their transmission customers.

In order to do that, they have to know what the resources are that are going to be serving that load. And with native load customers, that's a fairly straightforward process. They have plans in place and it's their generation.

With non-native load customers, it's a little bit more difficult. If you have long-term power contracts, then it's a little bit easier to design what you need to put into place to serve those interior load customers. If those contracts -- and they have a lot of short-term contracts -- and those contracts are turning over every three years. One year it's coming from the east, the next year it's coming from the west, the next year it's coming from the north. It's a little bit more difficult to design that system to meet that type of turnover.

And in fact, that seems to me to be kind of a foundational problem. Transmission systems last a long time and sometimes contracts don't. Sometimes contracts shift, and we see a lot of shifting contracts in Missouri and we see it even within our utilities that are buying it wholesale. And it's difficult to deal with that issue. What I would say is that we attempt to deal with it from the Missouri Commission standpoint where we have authority which is with the regulated utilities, the investor-owned utilities. We don't deal with the munis and we don't deal with co-ops in Missouri.

And recently in a complaint case, which is a rate reduction case in Missouri, we negotiated it as part of a settlement to increase the import capability into a service area because we had seen through several competitive bids that we weren't getting the cheapest alternatives because the transmission wasn't there to support the competition.

So those are difficult and individual types of issues that we've had to deal with. I don't see participant funding particularly fitting into any of that so I might be in agreement with some of those people that maybe they call that reliability I don't know but I think some of it is economic as well.

The other aspect that you have to deal with are what I would call the through and out transactions, the export problems that Sam Bratton brought up that exist in the South. In Missouri, we don't have the export problems. We have a lot of through transactions and a lot of transmission that's been sold on a firm basis physically today for through, and our perspective of that is that it needs to be on the same basis that that interior load is. In other words, there needs to be some kind of long-term support for expanding the transmission facilities to support through and out transactions. If it's a one-year deal, a two-year deal, and then that's going to go away, who's going to pick up and who's going to pay for the transmission?

And I'm afraid we know who's going to pay for it, and that's going to be the load within that zone or within that area will end up paying for it under some of the transmission policies that we've seen. So I don't know if you'd call that participant funding. I've been trying to figure that one out you know. If I want to buy through transmission because I've got a 20-year contract, and if that's participant funding, then that's participant funding. Because there is a long-term commitment there to support that transmission system and to pay for it.

And I think that's the fundamental basis upon which Missouri looks at how to get transmission built. If the funding's there, if the load's there to support if, if it's going to be there for a significant amount of time, then it's going to get built.

And I also want to -- this isn't a thing on CRRs, but I'll support what Martha had to say about if you've paid for it, then you should get the congestion revenue rights for it.

That leaves a lot of other problems to deal with, and I realize that. If I have a three-year power contract, am I going to put up the money up front and then hold the CRRs and hopefully I can sell them and get some of my money back in the future, is that going to bring that kind of investment to bear to support those short-term projects? I'm not sure that it will, but I think that's something that needs be thought through and I don't have any great answer for that.

Thank you for giving me time to make some comments.

MR. HEGERLE: Mr. Bergeron from Maine.

MR. BERGERON: Thank you. I will do, since it's late, and I'm sure everybody wants to end this session as soon as possible, I will do what the safe thing for a staffer to do is and read the remarks that the Commissioners sent me down here with and answer questions.

MR. HEGERLE: Good man.

(Laughter.)

MR. BERGERON: The Maine Commission appreciates this session and an additional opportunity to share our views on standard market design. We think that the Commission's got it right, that you've correctly identified some of the major barriers to transmission system expansion. You stated it in the NOPR, that mismatches between those who benefit from the new facilities and those who pay for them, particularly when the two affected sets of customers are served by different transmission providers, are often more than enough to make sure the new facilities don't get built. We're in the throes of just such a situation in New England and we can, from experience, testify to the accuracy of the NOPR's observation.

We're supplying a discussion paper and written responses to the Commission's questions on transmission expansion that provide more detail, but we'd like to take the opportunity to emphasize the central principles that should guide the Commission.

The first one is that your proposal to allocate transmission expansion cost to project beneficiaries is appropriate. Proposals for transmission system expansion are always motivated by economic factors. Those of us who have sat in on state siting counsel proceedings have seen those studies. They demonstrate project benefits exceed project costs, and they routinely produce the proceedings.

Transmission projects that are economic will not become any less economic if those who receive the benefits are also called upon to pay the costs. Where the costs are spread too broadly, however, project development will be more difficult because those who will be asked to pay but who will see little or no benefit are likely to resist development and payment.

To the extent that socialization has worked in the past, it's worked, and this is particularly true of New England, it's worked because the benefits of lower cost generation made available by the new transmission were shared as well. With the advent of LMP, however, transmission as well as energy must be locationally priced.

The second principle is that rolled-in pricing for expansions is fundamentally inconsistent with LMP and standard market design, and you've heard that from a couple of speakers today. The Commission's proposed rule for a standard market design provides the framework for competitive wholesale electricity markets that correctly places both the burden and the rewards of congestion in the hands of the generators or load interests that are responsible for creating or relieving it.

The design should work well both in states that have moved to retail competition and those that have not. Generators who incur the expense of locating in difficult load pockets will receive the higher prices that are associated with load pockets, and load interests who incur the expense of developing load response programs will receive greater savings due to the congestion pricing attendant with LMP.

Rolled-in pricing, however, thwarts the economic incentives that LMP is designed to provide because it taxes consumers who don't directly benefit from transmission expansion to relieve congestion. Spreading the costs beyond those who benefit blunts the incentives for those who should have the greatest economic incentive to relieve the problem.

Moreover, rolled-in pricing for transmission tilts the economic balance in favor of transmission as against other solutions such as demand reduction and new generation to locally high prices.

We hope these comments and the written materials that we're submitting will be helpful. We'll submit additional comment on this issue in our January comments in the docket and we thank you for the opportunity to participate in the technical conference.

MR. HEGERLE: Thank you. Ms. Westerfield?

MS. WESTERFIELD: Chairman Wood, and Commissioners Brownell and Massey, I appreciate the opportunity to speak. I was not scheduled to speak. I'm really at a conference upstairs. but I've been cloned and so I'm here also. But I would be remiss in my duties if I did not thank you for the opportunity you have given the Western States to develop a unique response of their own to standard market design and the state commissions along with other industry participants who are working hastily on that, and we appreciate that opportunity.

I think some very excellent comments have been made by my colleagues here at the table, and I would just simply add, picking up on something that Commissioner Mettner said, if you think jurisdictional separations are Byzantine, then transmission planning is at least medieval.

Transmission planning is an area that I think will certainly come to the forefront and is certainly an area I think you could say has been neglected for a number of reasons over the past decade. It's not that there are not good transmission engineers out there, it's just that the uncertainty in the industry at large over the past ten years since the Energy Policy Act of 1992 has not been real encouraging or created the certainty necessary to get people to put their money into transmission projects.

And I guess I just would speak to the fact that in addition planning, which certainly in the West we believe is best done on a regional basis for transmission to maximize benefits because, as you know, the distances we cover are very long and very expensive in the Western U.S., particularly with many of our power plants located very distantly from load.

Transmission planning has got to acknowledge, and I think this is a place where states can provide some meaningful input to whatever type of process FERC comes up with, to deal with transmission costing, planning has to take into account the dual role of transmission. It has to be there for reliability, to ensure that adequate service is delivered. As you know, all the states are charged with that task to ensure that that occurs, but now it's also been asked to serve as a market highway.

And so the planning function and the allocation, although of those functions has got to be undertaken in a way that attempts to be fair of course, recognizing that regulation is not perfect, the cost allocation process is, although scientific according to some, it does require a great deal of judgement, and ultimately that will be your judgement.

And so in the case of recognizing this and recognizing that there are many projects that have been delayed or deferred over the past ten years, you've faced a difficult task in deciding who should pay for what, and I think many of my colleagues have spoken to that issue.

I would also emphasize one other point, and that is just that certainty I think is a process and cost recovery have been mentioned by many of the speakers today and I think that that is key. It's not just creating an avenue for building transmission at every opportunity, it's ensuring that when it is built it's used and useful, and the costs are recoverable.

And I think all of us would acknowledge at the state level, if you've ever been through a siting proceeding for transmission, even if it's just a local line, those are often extremely difficult, so we can't ignore the fact that these are above-ground facilities, and even in the West where we have wide open spaces, the aesthetics of your view lends a lot to your property value. So it's not an easy issue whether you're talking about urban areas or rural areas, and I would just draw that to your attention as well.

Thank you.

MR. HEGERLE: Okay. I think we have some time for questions now. Do you all have something you want to start with or? Kevin?

MR. KELLY: Well, actually I have a question for Mike Proctor. I anticipated incorrectly where you were going. You laid out I thought beautifully the problem of contracts both inside a control area and for export being short-term, and where I thought you were going to say is therefore you wouldn't want to build for such things and roll it in, forcing those costs on folks, you would go with participant funding so that if the person who had the export found it valuable enough to amortize that over three years, or bet on future uses, that participant funding was just the right thing.

But I was entirely wrong. You laid out the case and then said, and therefore, you don't see how participant funding fits in. So knowing you have a PhD in economics, and it wasn't just a dumb comment, and that it was more my dumb listening, I thought I'd ask you to expand on that a little bit.

MR. PROCTOR: Well, I probably would have said what you said I thought I would say if I had finished the thought in my mind.

(Laughter.)

MR. PROCTOR: But there's some real difficulties with giving CRRs to someone who wants to use this for short-term type of thing. And there's some risk there. And I was thinking of it in terms of are you really going to get someone to provide the funding? If I'm going to do a three-year deal, and then after that, and I've paid for a facility that's going to last for 40 years or whatever, and after that, the benefit that I get from this is I've got the CRRs, I'm not doing my deal any more but I've got the CRRs, then everything rests on what the value of what those CRRs are.

Now if transmission were a very incremental type of investment, so that I could just invest just enough and it might work well, but a lot of those projects are going to be lumpy and those congestion revenue rights may not have much value the fourth or fifth year out. And I thought about how do you solve that problem. I don't like the answers. I've got some answers but I don't like any of them yet.

One of the particular answers is, is that you don't allow that additional transmission transfer capability into the simultaneous dispatch until somebody's purchased the CRRs for it. In other words, you kind of artificially, you force it to have value in the market. That was the kind of thing that I was thinking about when I said I'm not sure if it's going to work. I think it is the way to go, but I think some other things need to get worked out.

MR. O'NEILL: Are you sort of suggesting maybe a reservation price for the transmission rights?

MR. PROCTOR: Yes.

MR. KELLY: I think I've detected sort of a trend all day that people who are in areas with LMP up and running or shortly to be up and running really see the benefit of participant funding and how it fits in, with a few exceptions. And the opposite too. If you are not close to having LMP, that you pretty much conclude it wouldn't work. You historically roll things in. That's how you get things built, and you can't see participant funding really working well. Is that roughly right do you think?

MS. MORTON: I just have an observation. You know, it seemed to me sitting here listening to folks that they may be not meaning the same thing when they say participant funding, so I would suggest maybe the terminology "beneficiary" or "cost-causer" may be more appropriate, because you know, the idea suggested about the people who pay for the embedded costs should receive the congestion revenue rights, somehow this gentleman assumed it meant something else. And it does mean that, you know, they are participants, and those people, the embedded costs, you know, paid for by the retail load, would be paying it. They are a participant under that definition. They're a beneficiary.

So I think, you know, you might have used the definition to mean IPP or market, and that's not what I meant.

MS. FERNANDEZ: I was wondering if this one where if you said "voluntary" as a definition of participant funding that basically so it's almost like if someone believes they're going to benefit from it, they'll fund the expansion, but otherwise it wouldn't be included in the base plan unless it's necessary for liability. If that would perhaps address more your --

MS. MORTON: Yes. I really do think that

distinction needs to be made, and I would even further suggest that if an investment is decided or termed as being mandatory, that it should have a strong reliability emphasis on it but it could serve an economic purpose, and we do that on a state level.

But what we do at the state level is to have a certificate of need. And I think if you're going to go down that road, I think the similar process needs to be developed on a regional or even at FERC, that if you're going to have a regional transmission project before you make it mandatory and make everybody pay for it, that you need to have a certificate of need process like we do in the states to make sure that it is needed for whatever reason.

MR. BERGERON: Just a finer point on that. I think the first best case is to have voluntary participation, voluntary funding, but if your second step is to broadly roll in the prices, then you risk the incentive that other speakers talked about earlier today where, and things that the Commission has correctly noticed in the past, where if you defer an economic situation for a long enough period of time, it becomes a reliability problem.

And so you need to have I think a third step where you, if people don't step forward voluntarily and you decide that a crisis is approaching, then you need to make some kind of cut at who should pay for the cost of the upgrades, and you should do it according to the way it's spelled out in the NOPR, to try and roughly allocate the costs according to the beneficiaries.

MS. FERNANDEZ: So that if the RTO determined there was a major market, or a potential for a market failure major problem that wasn't being corrected, then there could be a mandatory beneficiary pays with the identification?

MR. BERGERON: Well, there might be. I mean here's a half-baked thought for you. But one of the problems that we have, and it was spelled out for the gentleman from National Grid, is that if you pass the hat, nobody's going to put any money in it.

Well, in the Northeast where you've gone to retail access, there is nobody to pass the hat anymore. Maybe one thing you want to consider is having the RTO do its planning process similar to the way it's done in New England, the RTAP process that the man from NU spoke about.

But after the system, the ITP or ISO or whatever, has done a system plan and identified the benefits, that might be the time when the Commission has talked about involving the states where the ISO approaches the state that is going to receive the benefits, and says look, this is our best cut. We've done this planning process. These are the benefits. They're real benefits to the residents of your state. Do you want this transmission project? And if so, here's how we think the costs ought to be allocated. And that frees the ITP that doesn't really have the jurisdiction to allocate costs on its own and allows the states their buy-in that the Commission desires.

MR. DOWNS: This is Don Downs joining by telephone.

MR. HEGERLE: Oh, excellent.

COMMISSIONER BROWNELL: Thank you.

MR. DOWNS: And thank you, Commissioner. I'm very sorry. I want to apologize to you all. I wound up at a legislative meeting and I couldn't extricate myself until now.

MR. HEGERLE: If you have any remarks you'd like to share with us, we'd love to hear them.

MR. DOWNS: Well, I guess what I'd like to suggest to you is that here in New England we have a situation that may be a little bit different than it is in other parts of the country, because we are well down the road into competitive markets.

We have already developed an RTO, for example, and an ISO, and we find ourselves in a situation where we have some transmission issues in particular that are kind of holdovers from the old world, from the old regulated world, if you will.

I will say there are at least four substantial congestion areas in New England for which transmission would be a partial or perhaps almost a complete fix. We have spent a lot of time, as both New England Commissioners and the New England ISO, trying to sort out these issues and trying to determine what would be a fair way of dealing with the various transmission problems, and I think all of us, no matter what our position is on the four congestion areas, I think all of us would agree that going forward into the future that as a general proposition, the great principle that needs to be followed is that transmission costs should in fact be borne by those who will benefit from transmission upgrade.

I personally find the idea of trying to distinguish between "reliability" and "economic" benefit as being almost impossible. I have yet to see the first transmission project that is clearly one or clearly the other and not some elements of both.

I suggest that perhaps what is needed here is a transitional policy to resolve the transmission issues that are holdovers from the past situation, and I suggest that to some degree, socialization of those may not only be desirable, particularly with respect to the underlying 345 kV grid, which happens to be the standard here in New England to the underlying grid, but perhaps with respect to some of these other pieces as well.

And frankly, as a practical matter, I think it's going to be very difficult for some states, particularly smaller states, to be able to actually finance in a reasonable and rational way the transmission costs that are in front of them.

My friend Chairman Dworkin I know is -- and according to ISO New England, the fixes in his state are going to be somewhere in the range of $140 million, and you know, that's a lot of money for a very small state with a very small population.

I respectfully suggest that socialization is something that has been employed for some period of time, not only in situations where equity demanded it but frankly, even in situations where is was a financial necessity.

Moreover, we employ socialization in a variety of other contexts. Frankly, the telephone service in Northern New England depends to a large extent on socialization of some of the costs involved, and that stems from an appropriate public policy which says everybody ought to have telephone service. And I suggest that this again is one of those situations. I think everybody feels that everybody ought to have electric service. To the extent it helps one more states achieve that, that would be appropriate. So that is my perspective on where we are in New England anyway.

COMMISSIONER BROWNELL: Thank you.

MR. DOWNS: Yes, ma'am. Thank you.

MR. HEGERLE: To me those comments beg the question -- and it's late. I'm tired. Maybe some of you have answered it already. Maybe all of you have answered it already, but I'll ask it anyway and you can tell me I missed it. But should some transmission be constructed simply for the purpose of supporting competitive markets, for addressing market power concerns, for avoiding market power mitigation, should any of that occur? And I'll open that to anybody. Hearing a no over here.

MR. BRATTON: I'll take a shot at that. As to generally the cost of rolling in the cost of the transmission expansion simply to support competition, I think we would probably have some serious concerns about that.

I have given at least some preliminary thought to the issue of the market power, and is it appropriate to apply a different standard there. And while I understand the relationship between market power and competition, it does strike me that there may be instances where there is sufficient market power in a region that the benefits that could be attained for the region by mitigating that market power by transmission expansion could certainly justify a rolled-in pricing under the appropriate circumstances. And I can't tell you what all those are because I've just started thinking about it.

MR. HEGERLE: Thank you. Next.

MR. VASINGTON: I thought it was an interesting discussion earlier talking about the need to compare the going forward incremental cost of a transmission solution to a problem to the going forward incremental cost of a generation solution to a problem and not be looking at the historical cost, because that leads us to I think the answer to the question, which is, if there is a market power problem within a load zone, then the question is, what's the most efficient solution to the market power problem within that load zone?

And to the extent that the transmission solution to that problem where the costs are localized, then the people of that region have a comparison to make between the incremental costs of the transmission solution to that market power problem versus maybe an additional generation from an owner who is not currently in that market could resolve that local market power problem.

MR. HEGERLE: The people in the region meaning the people in the load pocket itself, or in a broader region than that?

MR. VASINGTON: No. I mean within that load pocket itself. If you're talking on a zonal basis and you've got a zone that has a local market power problem, and you've identified that transition solution that has local beneficiaries only to solve that market power problem, and you allocate the costs accordingly, then the planning structure should take into account -- that will necessarily take into account the going forward costs of that transmission solution versus, say, some other solutions to the problem.

MR. HEGERLE: Chairman Dworkin?

MR. DWORKIN: Thank you. You asked whether it would be appropriate to pay for transmission for the sole purpose of supporting competition.

MR. HEGERLE: Yes.

MR. DWORKIN: And answering it, like a lot of questions, turns on what you mean by the question. I think I'm going to give you an answer that's the same as what the last two folks said, which is this: If you mean by it to support competition, in other words, making an investment to make competition look better than it otherwise would, and paying for it through funds that you collect in a mandatory, socialized way, then what you're doing is just creating a subsidy to try to make competition look good. And if you do it, you ought to deduct the cost of that subsidy from the otherwise asserted benefits of competition, and since those are in the two to three percent range, you can wipe them out pretty fast, and you might as well go back to cost of service regulation.

So I think the answer is no.

If you mean by it that there are times when there is market power that could be alleviated by an investment in transmission, it would open up options that would significantly reduce the market power, then I think those situations will occur, but I wind up in exactly the same place as Paul Vasington, which is there are likely to be a lot of different solutions that might solve that problem, and one of them is putting new generation into the load center.

Another is putting more efficiency into the load center. Another might be a transmission line that helped the whole region, not just the load center. And you want to have a test that picked the best result for all of them and pooled them all equally instead of pooling some of the solutions and not the others.

I think that's what Paul said. He's nodding, so I'm really happy to agree with it. In that case what you've really got is plain old investment in transmission to alleviate an economic problem, trying to draw a bright line between solving market power, solving economic tension and solving reliability, is really three central points at different spots on the continuum. And I don't think you buy anything analytically helpful by trying to call them different categories. You just wind up with saying is the investment cost justified in the least-cost way when compared with the alternatives when they are all equally weighted in terms of how they would be pooled?

That's my resource parity concept I started with, and I don't mind to get a chance to say it again at the end.

MR. HEGERLE: Thank you.

MR. METTNER: I'm going to agree generally with what Paul said. And again, speaking parochially from Wisconsin's perspective, it depends on what you mean by market power. Setting aside for a second behavioral market power which should be either through withholding capacity or strategic bidding, what I would say, you know, abuses of market power.

Setting that aside for a second, in Wisconsin we've approached a structural solution to vertical market power, which is the tendency of a generator as one who owns generation to favor his own generation with respect to the use of the transmission grid. That structural solution is requiring all of our transmission-owning entities or previously transmission-owning entities to contribute them to a common entity which is the American Transmission Company.

This alleviated some of the litigation that you saw before the FERC and '98 and beyond where transmission dependent entities, generally consortia of municipal electric utilities, were litigating the issue of the capacity benefit calculations, and again, reasonable people might differ on this, but there was a tendency for those who owned transmission to manipulate CBM, depending on whether you thought you'd thought you'd be flush with capacity that summer or whether you thought you'd be having to go outside the region to get it.

That's one structural solution. Now sitting with the system that we had today, you have structural market power within our constrained interfaces in the Wisconsin Upper Michigan. And in fact, we have one player that is very dominant in their share of the market for generation. Yes, it's a good idea to construction transmission to alleviate that structural market power for I would think of reasons which benefit the system and their customers.

Number one, it would theoretically open up new network resources outside of that constrained region so that (a) that generator could sell into a region where they otherwise might be constrained by the existing system, and it gives the customer within the warmest region more options for purchases. So I think that, again, subject to the marginal costs of those and how they compare with building generation inside the constraint, you have a set of options there, but all of them viable and presumably should be looked at, and all of them which produce systemic reliability effects which I think should make them susceptible to being part of rolled-in pricing.

I'm just agreeing with Paul in a slightly more provincial way, I guess.

MR. HEGERLE: Thank you. Mr. Bergeron?

MR. BERGERON: Yes. I'll make this brief. There's just two things. I've been involved in a lot of transmission proceedings, siting proceedings in the last 15 years or so, and as LuAnne has attested to already, it's a very difficult situation. You often pit small landowners against the utility company, and you have to have a really good motivation and reason for doing it, for siting the transmission facility.

The second, we are economic regulators, and it becomes very difficult to justify to our constituents why you would build a transmission line on the basis of improving competition. We've done it, and it hasn't been easy.

MR. HEGERLE: Ms. Morton?

MR. DOWNS: I'll take a page from the gentleman from Wisconsin and suggest that if you are willing to accept a fairly broad concept of market power, in the sense of trying to build a market which has a free trade kind of an arrangement, if you will. In other words, all generators were able to reach all regions, and prices are driven by the sum total of all the generation in the area.

Here in New England, for example, we have a couple of situations, notably in Southern Maine and Southeastern Mass and Rhode Island, where we have a number of generation units that are in essence trapped behind those walls, if you will.

And behind those walls, we have fairly low prices because there's an awful lot of generation in there that's chasing a relatively small amount of load, and on the other side of those walls, we have somewhat higher prices because they can't get access to that generation.

I suggest there are two problems with this. One of them is that it creates artificially different prices within the same region simply because you can't move power across those walls, if you will.

But more to the point is, at least for me here in New England, we manage close to 30 percent capacity over the course of the last several years. Frankly, if we aren't careful about it and we don't move reasonably quickly to resolve some of those problems, particularly in Southern Maine and Southeastern Mass and Rhode Island, some of that generation and capacity is ultimately going to be lost simply because those generators in those areas are not going to able to sell across those walls, and eventually they will take those plants out of service. And that in turn is going to drive up prices everywhere.

So I recognize that it isn't necessarily a traditional view of market power, but if FERC is in the process of trying to build free markets with large bases so that there is increased reliability and stable prices, I'd suggest that this clearly achieves that goal.

MR. HEGERLE: Before we leave the phone, does Chairman Hemingway have a comment as well on his one? Don't want to leave you out if you want to participate.

(No response.)

MR. HEGERLE: Okay, hearing none. Ms. Westerfield on the end there.

MS. WESTERFIELD: I just waned to clarify that when I said, no, that meant, you know, your question was whether or it's okay to socialize costs to alleviate market power, and I would say, no, from the perspective of bundled retail load in the Kentucky, if not a market power problem in Kentucky, and in fact it's still fully regulated, so there's not a market there. So I really don't see a reason for Kentucky customers to pay for that.

But that's not a show stopper for you guys. I mean, you know, if you want to take your portion of the costs and socialize them, as long as they aren't assigned to Kentucky retail customers, then we wouldn't have a dog in that fight, and I think if you can try to structure the systems to that doesn't occur you'll probably find fewer objectors to what you're trying to do.

And, you know, along those lines, I would agree in concept with some of the early speakers about separating the costs between local and a super highway system. If we had kept our local zonal costs and we had control over what those costs were that were passed over, passed on to bundled retail load, whereas the super highway costs were only assessed when we actually used the super highway, I think we could live with that a lot easier.

You may do a lot of things on that super highway that we don't agree with, but as long as we're using it, I think it's appropriate to pay it. I just don't want it arbitrarily allocated to our retail customers just because we're a good funding source.

MR. HEGERLE: Agreed.

MS. WESTERFIELD: I would just like to amplify a little bit on former Commissioner Bratton's maybe. I think your original question was should transmission be built for the purposes of competition? I don't believe your original question said anything about who would pay for that. And my response to the original question is, that should be a tool that is not put by the wayside. It should be in the tool box. You know, don't throw it in the garbage yet.

You never know, and of course, those of us who have been around a long time, ten years ago no one could have anticipated that we'd be sitting here talking about these topics concerning how wholesale markets should operate. So you never know what might come in handy.

If your choices for purposes of competition were shutting down power plants or building transmission, for instance, or any other number of alternatives that might be less pleasant than building transmission, although for some of us, as Dennis has mentioned, transmission siting is very difficult.

But I just would say don't throw that out of the tool box. And it would depend in large part on who would pay for it. But don't preclude an entity who wants to take that risk on from doing so.

Then another scenario where this might be a factor, at some point congestion management has got to become congestion relief. You can only manage for so long before lights start going out and you really do need more transmission. So I would just mention that as a possible place where that might come in handy.

MR. HEGERLE: Thank you. Dave, do you have a question?

MR. MEAD: Yes, thanks. Of course, transmission siting is a responsibility for the states. And the question I have relates to that, and that is, especially in those states where transmission is being proposed where you think a lot of the beneficiaries are not in your state but outside your state, would your willingness or even ability in view of your statutory responsibilities to approve that transmission depend on whether there was a policy of rolled-in versus beneficiary pays?

MR. BRATTON: I think that's certainly the view in a number of Southeastern states. There is at least one jurisdiction that I'm aware of where without having read the statue, I'll accept the view of the Commissioners there, that their statute would absolutely preclude rolled-in pricing of a transmission project that provided at best indirect reliability improvements in that state, that unless there were direct benefits in the state, they would be precluded by law from doing so.

As a practical matter, as others have alluded to here on this panel, transmission siting is at best a difficult process for state regulators. We have not done a lot of it lately. What we have done has been relatively short lines that were absolutely essential. But for any jurisdiction to site a major transmission project across a portion of its territory when the primary beneficiaries are on either end and outside the jurisdiction would be very difficult politically.

I am reminded of a conversation I had with Chairman Hecker early in this debate, and I observed that in doing these types of projects, we'd find out how many statesmen there were among the state regulators. I'm not sure there are many of us, or any of us.

MR. DWORKIN: Thank you. I'd like to describe two stories that help answer the question. The first is that if you look at a transmission map of New England, you'll see that the single most important source of power for New England is the transmission line that starts south of Montreal, crosses the northeastern third of Vermont through a rather rural area called the Northeast Kingdom, crosses the corner of New Hampshire, and winds up in western Massachusetts where it feeds into the total New England grid.

That was permitted in 1982 and physically constructed in '84. You can imagine that the proceedings as to whether it would be put through Vermont's wildest area were contentious, and they were, but it was also granted.

And the logic of the grant was set out in the Public Service Board's order in two ways: Part of it was in the kind of language that we all speak and write in our orders, talking about benefit to the state, where it then talked about net regional benefit, the existence of a regional power pool. The reliability of the totality indicated that even if most of the power would go to other parts of New England, the benefit in terms of overall reliability, lower loss of load probability and all the other kinds of things that we cite, added up to enough of a benefit to justify putting it in Vermont.

The second part that the Board cited in its order was a little bit simpler version, where it quoted what a dairy farmer who spoke at the public hearing said. And what he said was, if we're going to sell our milk down-country, we want them to be able to run the refrigerators to keep it in.

And the Board cited both of those, nice regulatory-speak, and nice English-speak, because both of them are parts of the fact that we are a commonality. For those of us that have been a part of the tight power pool for 30 years, it was actually an easy thing to think about. It fit to the way we think about the world.

We can make those decisions, and we can look at it, so in the simple sense of can we think about benefits to the region and reflect that they may have benefits, even if they're indirect within our state, the answer is that we've proven we can do it.

The harder question is what does pooling do about that? The answer is harder because if we are given two choices of ways to solve a problem, and one choice has us exporting costs out of our state to be paid by the total pool and another, cheaper solution has us paying all of the cost from within the state, I'm going to look at a statute that tells me to pick the least-cost alternative, and I'll look at it as the Siting Board, as much as the Utility Commission, because we're one-stop shopping in Vermont.

And I'm going to have an unresolved legal question about which one do I pick? Maybe the answer is, I pick the one that assigns the costs all out of state, because that's first cost, lowest cost.

Or maybe I figure that if I assign enough cost out of state, I'm going to wind up having to pay for other states doing the same thing, and it will bounce back to me. And I take, if you will, the more sophisticated, broader view.

On the other hand, it's going to be pretty speculative if I don't know where states are going, and if you affirm a set of rules under which some solutions are spread and other solutions aren't spread, I'm going to have a very nasty problem in my hearing room when that case walks in the door.

MR. PROCTOR: I'll make my answer very short: If the alternative was building, say, transmission for out-or-through transactions relative to the service territory in Missouri, and have the individuals, the customers within that service territory pay for it, that's got about a zero chance of getting approved -- maybe less than that.

If, on the other hand, there is someone else, benefits-driven, the people that are needing it are going to pay for it, it's got a much better chance. I'll just leave it at that.

MR. HEGERLE: Thank you, Commissioner.

MR. DOWNS (By Telephone): Let me offer you a slightly different fact situation that I think also illustrates part of this. If you look at the situation in Maine, we have a transmission constraint there in the southern part of Maine.

Now, if we stick to the idea that the state in which the transmission where work has begun is the state that has to pay for it, Maine has an insoluble problem, because you will be asking them, in effect, to bear the entire capital cost of fixing that transmission constraint.

And their reward for doing it will be higher prices, because their cheap generation will migrate out of the state. In essence, if you stay in the mode of saying, you know, all the transmission that happens in a particular state has to be paid for by that state, then the constraint in Maine will probably never be resolved, because there is no way that the political equation can work there.

They cannot go to their constituents and say, look, we need to spend x-number of million dollars to repair this problem, and, by the way, at the other end of that, we're going to wind up paying higher prices as our reward. That clearly is an equation that does not work.

And at the end of the day, socialization of those costs may not be everybody's favorite idea, but it's hard to see how we are going to resolve some of those problems unless some of those states are going to be able to get some help from their neighbors.

MR. BAEZ: I was just going to offer to echo some of the sentiments that have been expressed. The short answer to the question is, even if it was participant-funding or any other way that was particularly attractive, that doesn't get rid of the political problem.

Certainly, speaking from a state that probably doesn't have the conditions to make it amenable to even have a question like that, I mean, the hanging part -- the hanging down part of our state, as someone described to me, you know, basically you've got a big lake in the middle, a National Park at the bottom, and along the sides, you've got very expensive real estate development.

And I don't think that the fact that someone else is going to pick up the cost for transmission to someone else's benefit is going to have any particular incentive for that to be an acceptable project in our state.

And I guess that in a roundabout way, that sort of plays up probably our stance or certainly my stance or feeling on a previous question. You have to -- for those reasons, I mean, for those geographic reasons, certainly that exist in our state, we have to be able to maintain a generation alternative available to us in order to address market power or any other conditions.

We can't always run to transmission. In fact, I think, more often than not, we may not be able to run to transmission.

So, in our particular case -- I don't know, necessarily, that it exists anywhere else -- but in our particular case, we have to maintain a generation alternative available to us, because in many respects, it's going to be the better option.

MR. METTNER: The short answer: I'm trying to answer your question kind of within the constraints of what Sam said, and it's easier to be a statesman when you're not coming to the game with an empty hat or the worst possible argument before your constituents.

EVENING SESSION

(6:00 p.m.)

MR. METTNER: And siting the two longest lines that have been before our Commission in a number of years -- and I'm not saying anything that other Commissioners here and on the phone don't know -- I mean, you can -- we have the ability to trump local zoning by granting a construction certificate in our state.

And when we exercise that authority, oftentimes you get called things, names I haven't heard since I was in high school. And it's a very emotion and contentious thing.

Although I have a colleague who tends to be -- you all know him -- he tends to be less persuaded by emotional things than I am -- who, in the face of a protest over a power line proposal, asked the leader of the protesters, what do you think this is, an election?

And he's trying to put a point on the idea that it's an administrative proceeding that's going to be guided by a record. I think that the Arrowhead Western Line is a very instructive example in the increment. And it was a significant increment.

The fact that that project was ultimately rolled in as an asset, a purported asset of the American Transmission Company, made it easier to make the argument, which is evidence, even with the predecessor two companies that were proposing it, that it is primarily for systemic benefit.

When you have lines such as that one where there are no step-down transformers anywhere along the way, that line takes on increasingly and indomitably, a character of common carriage. And it would be insulting for only the customers of Minnesota Power or Wisconsin Public Service, the original proponents of the project, to fund that themselves.

I mean, obviously, their assets, or at least in terms of Public Service, their assets are rolled into to the American Transmission Company, and the argument for the systemic benefit of that project became a lot clearer for the result.

Now, I contrast that with the Kasago transmission line, where if you look at our authority to certify property and trump local zoning, so you don't have basically a local veto over the projects, under certain circumstances and at certain voltages in Minnesota, every county through which lines of those size go, has to affirmatively approve it, which gives each county negative control.

Such opportunities for negative control over a project of any sufficient scope will doom it, necessarily.

Now, yes, you have to be a statesman about these things, I think, at a certain level, but it's a lot easier if you don't have the worst argument to make, which is that it's going to go through your backyard and you receive no benefit and you can pay for at all.

(Laughter.)

MR. HEGERLE: We have Ms. Morton and then Chairman Dworkin, and then we need to wrap things up for today.

MS. MORTON: I just wanted to point out to the gentleman on the phone that when he said that that problem that he described in Maine, that I don't really view that situation, you know, having the system pay for that line to relieve the congestion, as being socialized.

I think we've got a difference in terminology there. I think it's perfectly appropriate for the region to pay for that line, and it's not socialized when they do it, and the cost can be allocated to them through the CRRs. And they're going to receive a congestion revenue right for relieving that congestion, and they should be paying the embedded cost for it, along with it, and the people of Maine shouldn't have a cost responsibility.

MR. HEGERLE: Chairman Dworkin?

MR. DWORKIN: Thank you. I can't avoid the observation that what we like, we call pooling, and what we don't like, we call socialization.

(Laughter.)

MR. DWORKIN: When you've been an appellate advocate, you try to look for those kinds of things, but to move beyond it, I wanted to close, at least for me, with a couple of observations:

One is that I do think that you're not going to be able to duck this issue by relying on markets to solve it. Merchant transmission is a fascinating concept, but when we hear it discussed, we hear it being discussed in terms of tens of millions of dollars of investment. And the needs that we're talking about are measured in terms of hundreds of millions and billions of dollars of investment.

And given investor shakiness about complex and barely-understood concepts, in general, and about utility markets, in particular, the chances that investors are going to provide merchant transmission with billions of dollars, as opposed to tens of millions to solve problems where the need is widespread, rather than identifiable niche, are extraordinarily small.

So, I think that with all the respect that I have for the people that are trying to bring forward merchant solutions, I don't think we can rely on them, and I really want to counsel the Commission, FERC, to be very careful about designing a system through which billions of dollars will flow, out of a concern for the hopes -- and I might even call them dreams of some institutions through which tens of millions will flow. It's really important that you notice where the financial center of gravity is here.

The second thing is, when we think about what we can leave to the market, I think you phrased it this morning as how long are we willing to wait? And the answer, I think, is conceptually easy. It turns on how comfortable you are with putting millions of people's fundamental livelihood at risk while you try to deal with the kind of management by strategic brinkmanship.

You can't deal with management by strategic brinkmanship with other people's livelihoods in a state and be a moral person. You have got to in this situation, move relatively quickly to what I will call a social -- whether or not it's a socialized solution, where before the crisis is severe enough to prompt a market response, you've put in place, the mechanism that within a half a decade to a decade, will lead to the solution that you need.

That means that you need to have tools through which a lot of money will flow, which are, to be blunt, regulatory as opposed to purely market. And because you're dealing with something which is a lot of money, a lot of other people's money, collected through something they can't dodge, a non-bypassaable wires charge, you have an obligation to pursue the general good, not just the specific good.

And that's why the parity of resources is really important.

And, finally, I just wanted to take a minute to mention that the second parity I talked about was historic parity. And the story that I told about Vermont being willing to host the facility to benefit all of New England, is good example of the historic tradition of common endeavor, which is why it would be particularly egregious to ignore that in a flash cut to a direct allocation after a long history of common approach to solving problems.

And whatever weight you put on what I think you heard from a lot of folks, which is you can't assign all of the costs in the physical location, there is a fact that you've got a history of doing things together that is part of the just and equitable background of where we are right now. Thanks a lot.

MR. HEGERLE: Any closing comments from our Commissioners?

CHAIRMAN WOOD: In a broader sense, you made the case for why we're doing SMD, and I appreciate it, even though you weren't quite speaking to that.

And certainly, in my mind, the ability of the three great resources, which are customer response, generation, and transmission, to understand in this world, how they get their money back, is pretty darn important to the underpinning here.

And, quite frankly, one of those three is a directly-regulated asset and the other two are informed by the regulatory brush that we're painting with here, and I do appreciate all your efforts to help us get that art work just right. We will, and we will continue our efforts on resource adequacy and congestion revenue rights, and limitations on liability this month.

I want to thank Staff for your leadership on trying a little bit different format, and we want to build on it and do even more, so that these continue to be as productive and useful as all four panels were today.

I appreciate my colleagues and our friends at State Staff for the effort y'all took to come the distance, and we, as always, appreciate Don, you patching in on the phone, and Roy, as well. I guess that with that, we will conclude.

MR. HEGERLE: I just want to add to your thanks of Staff. Sarah McKinley has done a ton of work behind the scenes and in this room to make this happen, so we really appreciate her fine efforts here.

Thank you, and thank you all very much.

(Whereupon, at 6:10 p.m., the technical conference was concluded.)